NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

December 2, 2011

VIA ELECTRONIC FILING

Re: **North American Electric Reliability Corporation, *2011 Winter Reliability Assessment 2011/2012*, Docket No. RC11-_-000**

The North American Electric reliability Corporation (NERC) submits solely as an informational filing the *2011/2012 Winter Reliability Assessment*; a report prepared by NERC, released on November 30, 2011.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Winter Reliability Assessment

2011/2012

RELIABILITY | ACCOUNTABILITY

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Preface to 2011/2012 Winter Reliability Assessment

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.[1,2] NERC operates under similar obligations in many Canadian provinces as well as a portion of Baja California Norte, México.

NERC Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses reliability annually via a 10-year assessment and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[3]

Figure A: NERC Regional Entities

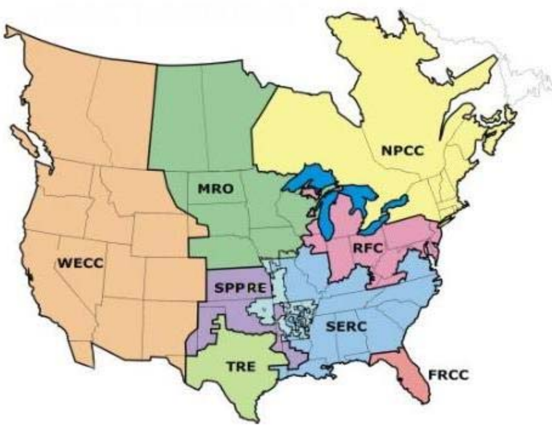

Table A: NERC Regional Entities

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

***Note:** The highlighted area between SPP and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://thomas.loc.gov/cgi-bin/bdquery/z?d109:HR00006:@@@L&summ2=m&.

[2] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[3] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently 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 standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. 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. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable.

Background

The *2011/2012 Winter Reliability Assessment* provides an independent assessment of the reliability of the bulk electricity supply and demand in North America for the period December 1, 2011 through February 28, 2012 (Table A). The report specifically provides a high-level reliability assessment of 2011/2012 winter resource adequacy and operating reliability, an overview of projected electricity demand and supply changes, and Regionally focused self-assessments based on Assessment Areas.

The primary objective in providing this assessment is to identify areas of concern regarding the reliability of the North American bulk power system and to make recommendations for remedial actions as needed. The assessment process enables bulk power system users, owners, and operators to systematically document their operational preparations for the coming season and exchange vital system reliability information. In addition, NERC does not make any projections or draw any conclusions regarding projected electricity prices or the efficiency of electricity markets.

Report Preparation

This assessment is coordinated by NERC in its capacity as the Electric Reliability Organization.[4] The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) prepared this report based on data submitted by the eight NERC Regional Entities and other stakeholder participants as of September 30, 2011. Any other data sources used by NERC staff in the preparation of this document are identified in the report.

Table A: Reliability Assessments Schedule

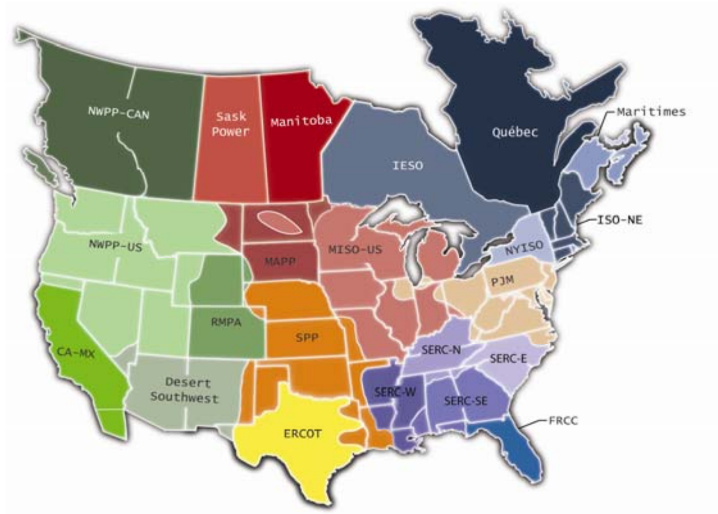
Assessment	Outlook	Publish Target
Summer	Upcoming Season	May
Long-Term	10 Years	Fall
Winter	Upcoming Season	November

NERC, in concert with industry stakeholders, performed detailed data checking on the reference information received by the Regions, as well as a review of all self-assessments, to form its independent view and assessment of the reliability projected for the 2011/2012 winter season. NERC also uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject matter expertise from many sectors of the industry. This process also provides essential checks and balances for ensuring the validity of the assessment and conclusions provided by the Regional Entities.

[4] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission." http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

Assessment Areas

Figure A: Assessment Areas Map



Based on recommendations from industry representatives as well as approval from the NERC Planning Committee, assessment boundaries were reconstructed beginning in 2011 to represent existing operating boundaries used in the planning process.[5] Prior to 2011, Regional Entity boundaries were used for NERC assessments; however, these borders do necessarily signify that planning and operations occur within a single Regional Entity. Therefore, assessment boundaries were enhanced using existing operational and planning boundaries versus traditional NERC Regional Entity boundaries (Figure A). Additional insights will be gained as planning and operations are aligned within each assessment area. Assessment boundary changes from 2010 to 2011 are outlined below (Table B).

Table B: 2010 Assessment Areas Comparison to 2011

Assessment Areas		NERC Regional Entity	Description of Change
2010	2011		
TRE	ERCOT	TRE	Area name changed to reflect the operator
FRCC	FRCC	FRCC	No change
New England	ISO-NE	NPCC	Area name changed to reflect the operator
New York	NYISO	NPCC	Area name changed to reflect the operator
Maritimes	Maritimes	NPCC	No change
Ontario	IESO	NPCC	Area name changed to reflect the operator
Québec	Québec	NPCC	No change
MRO CAN	SaskPower, Manitoba	MRO	SaskPower and Manitoba now separate assessment areas
MRO US	MAPP	MRO	MAPP Planning Authority, removed MISO
—	MISO	MRO, RFC, SERC	MISO RTO
—	PJM	RFC, SERC	PJM RTO
Central	SERC-N	SERC	Removed PJM RTO members
Delta	SERC-W	SERC	Removed SPP RTO members
Gateway	—	—	Removed, part of the MISO RTO
Southeastern	SERC-SE	SERC	No change to boundary
VACAR	SERC-E	SERC	Removed PJM RTO members
SPP	SPP	SPP RE	SPP RTO and residual SPP RE members
CA-MX	CA-MX	WECC	No change
Desert SW	Southwest RSG	WECC	Cosmetic – Name Change Only
RMPA	Rocky Mountain Reserve Area	WECC	Cosmetic – Name Change Only
NWPP	NWPP	WECC	No change, Data is presented for both the US and Canada portions of NWPP

Enhancement to Reserve Margin Calculation

A significant change initiated in 2011 establishes a more consistent method to account for Demand Response in the Reserve Margin (RM) calculation. In previous reliability assessments, some Controllable Capacity Demand Response (CCDR) programs were used to reduce Total Internal Demand (Net Internal Demand), and some programs were included as a supply-side capacity resource. In prior years, the

[5] Reliability Assessment Procedure: Subregional Restructuring to support ISO/RTO Boundaries, December 2010. http://www.nerc.com/docs/pc/ras/Reliability%20Assessments%20-%20Subregional%20Restructuring.pdf

Reserve Margin calculation was based on Net Internal Demand and capacity resources, which included some CCDR on either side of the equation. The new method calculates Reserve Margins based on Total Internal Demand.[6] CCDR is added as on-peak capacity, versus reducing Total Internal Demand. This enhancement allows demand to be analyzed irrespective of CCDR penetration, and consistent treatment of CCDR across all assessment areas. A comparison of the two methods is shown below (Table C):

Table C: 2010 to 2011 Reserve Margin Calculation

Pre-2011 Reserve Margin Calculation (Majority)	2011 Reserve Margin Calculation
RM = [(Capacity - (Total Internal Demand - CCDR)] / (Total Internal Demand - CCDR)	RM = [(Capacity + CCDR) - (Total Internal Demand)] / (Total Internal Demand)

Assumptions and Considerations

In the *2011/2012 Winter Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[7]

- Supply and demand projections are based on industry forecasts submitted in September 2011. Any subsequent demand forecast or resource plan changes may not be fully represented.
- Peak Demand and Reserve Margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned; planned outages take place as scheduled.
- Demand reductions projected from Demand Response programs will yield the forecast results if they are activated.
- Non-controllable and non-dispatchable Demand-Side Management programs are reflected in the forecasts of Total Internal Demand.

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[6] This change was recommended by the NERC Resource Issues Subcommittee under the direction of the NERC Planning Committee. The recommendation was approved by the NERC Planning Committee in 2010 and is detailed in the report titled *Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculation,* June 2010 http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

[7] Many forecasts report probabilities with a range of possible outcomes. For example, each Regional demand projection is assumed to represent the projected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC Regional projections, there is a 50-percent probability that actual demand will be higher than the forecast midpoint and a 50-percent probability that it will be lower.

2011/2012 Winter Key Highlights

Reserve Margins Adequate for 2011/2012 Winter Season

Anticipated Planning Reserve Margins for entities across North America are forecast to be adequate for the 2011/2012 winter season. Anticipated Planning Reserve Margins for winter peaking areas, which include MRO: Manitoba Hydro and SaskPower, NPCC: Maritimes and Québec, and WECC: NWPP-US and NWPP-CA are forecast to be above NERC Reference Margin Reserve Levels and are projected to have sufficient reserve margins to ensure bulk power system reliability throughout the 2011/2012 winter season.

Winterization Efforts Proceed in Southwestern United States

During the period of February 1, 2011 through February 5, 2011, the Southwestern area of the United States experienced unusually cold weather that resulted in the widespread loss of service to electric and gas customers. At the time of publishing in November 2011, there are several Regional Entity and state level initiatives underway in Arizona, New Mexico, and Texas to address the weatherization of generation and gas well-head assets and to ensure robust and reliable supply of fuel.

La Niña impacts weather during 2011/2012 winter season

For the second consecutive winter season, 2010/2011 and now 2011/2012, La Niña will influence weather patterns across the United States. La Niña is associated with cooler than normal water temperatures in the tropical Pacific Ocean. With this weather pattern in place, the US National Oceanic and Atmospheric Administration (NOAA) forecasts that areas located in Texas, Oklahoma, New Mexico and parts of surrounding states are unlikely to get enough rain to alleviate the ongoing drought. In Canada, Environment Canada forecasts that a typical La Niña winter will bring colder temperatures and more precipitation than normal, with La Niña effects particularly intense in western Canada.

Fuel Supplies appear Adequate for 2011/2012 winter season

Fuel supplies from fossil based sources (Gas and Coal as primary drivers) are expected to be in-line with expected winter season production and storage levels at the time of publishing. Additionally, there are no forecast disruptions in production or distribution of these resources (labor strikes, pipeline outages) that will impact the reliability of the bulk power system during the 2011/2012 winter season.

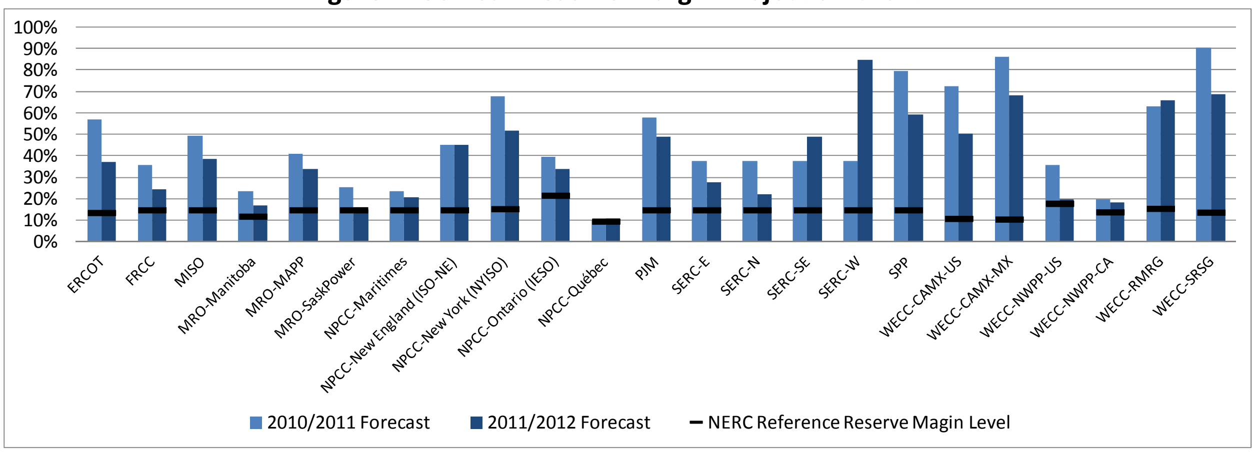
2011/2012 Winter Reliability Assessment

Resource Adequacy Assessment

All Regional Entities are projecting to have sufficient Reserve Margins[8] to ensure bulk power system reliability throughout the 2011/2012 winter season. Adequate Reserve Margins are essential for maintaining reliability by providing system operators with the flexibility needed to withstand unexpected generation or transmission outages and deviations from the demand forecast.

The winter peak Anticipated Planning Reserve Margin across North America (United States, Canada, and Mexico) for non-coincident peak demand[9] is expected to be 39.3%, which is 77 basis points (7.7 percentage points) lower than the 2010/2011 forecast.[10,11,12]

Figure 2: US Peak Reserve Margin Projection Chart[13]



A number of summer peaking regions within North America are reporting a lower Anticipated Planning Reserve Margin in comparison with 2010/2011, including ERCOT, FRCC, NPCC-New York, and PJM. Increases in Anticipated Planning Reserve Margins can be found in SERC-SE, SERC-W, and WECC-RMRG.

For winter peaking assessment areas[14], Anticipated Planning Reserve Margins are close to the NERC Reference Margin Level,[15] however these assessment areas continue to meet their reliability-based

8 In this report, "Reserve Margin" represents "Planning Reserve Margin". Reserve Margins for the upcoming winter are calculated by using projected on-peak capacity resources (generation, demand resources, and net transfers) and a 50/50 demand forecast, which represents a forecast value for an actual value having equal chance of either falling above or below the forecast value.

9 The non-coincidental peak demand is higher than the peak demand at any single point in time (coincident peak), as it takes into account each assessment areas peak demand over the winter forecast.

10 The North American bulk power system does not have the capability to transmit power across its entire expanse; therefore, a North American Reserve Margin is only a general indicator. It is not representative of resource adequacy within all Areas of North America.

11 The 2010/2011 Reserve Margin was calculated using the same method used in 2011/2012. Approximation was used in developing the 2010/2011 Reserve Margin – error was +/- 0.2 percent

12 See the *Demand, Resources, and Reserve Margins* section for the associated Reserve Margins by Country and Assessment Area. The tables in this section are the reference source for tables and figures in the NERC Reliability Assessment Section

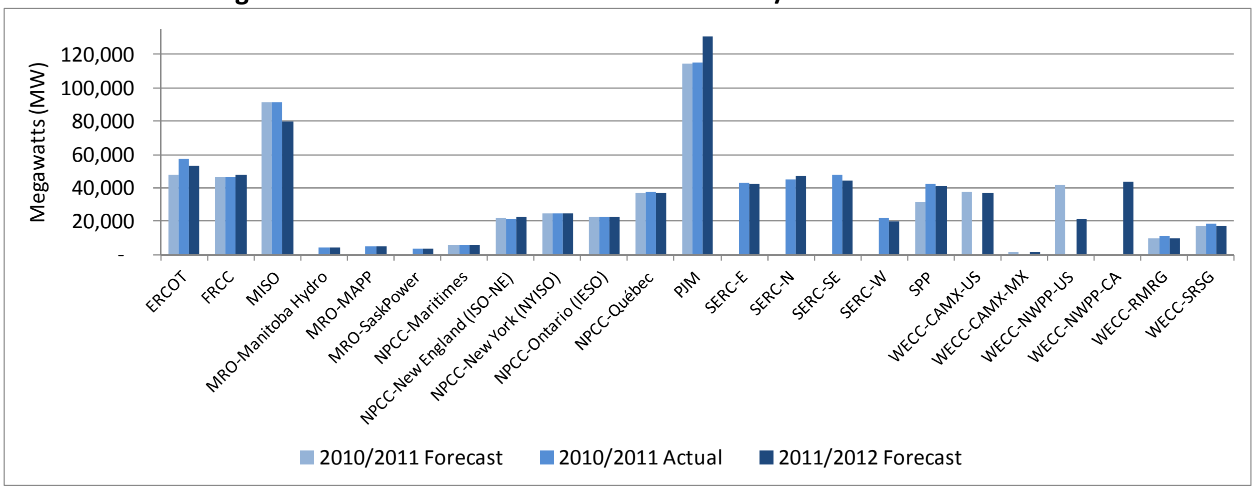
13 For this Figure, 2010/2011 Reserve Margins for the SERC-W, SERC-E, and SERC-N are based on the "old" SERC subregions of SERC-Delta, SERC-VACAR, and SERC-Central, respectively. WECC-SRSG and WECC-RMRG are based on the "old" WECC subregions of Desert-Southwest (DSW) and Rocky Mountain Power Area (RMPA), respectively.

requirements and appear to have sufficient resources to meet projected winter peak demands. The reliability of these areas would be most sensitive to significant changes in available generation or demand forecasts. However, based on the current winter forecast, reliability is expected to be maintained both in these assessments areas and NERC-wide.

Demand

Forecasted winter peak demands[16] across NERC appear manageable, with a number of areas projecting little to no growth compared to 2010/2011 winter seasonal forecast demand and 2010/2011 winter season actual demand[17] experienced. PJM demonstrates a notable increase in 2011/2012 forecast demand due to the integration of the American Transmission Systems, Inc. portion of FirstEnergy, Cleveland Public Power, Duke Energy Ohio and Duke Energy Kentucky since last winter. [18] MISO shows a decrease in forecast and actual demand from the 2010/2011 winter to the 2011/2012 forecast demand due to the loss of First Energy from the MISO system that was effective in June 2011.

Figure 3: Total Internal Peak Demand for 2011/2012 Winter Season



Less predictable economic conditions have resulted in a greater degree of uncertainty in the 2011/2012 winter season that is not typically experienced in a period of more stable economic activity. The 2011/2012 winter season non-coincident Total Internal Peak Demand[19] is expected to reach 760,679 MW for North America, reduced by approximately 37,945 MW of Demand Response available on-

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[14] Winter Peaking Assessment Areas (2011/2012): US: WECC-NWPP-US; Canada: MRO-Manitoba Hydro, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-NWPP-CA

[15] See the *Reliability Concepts Used in this Report* section for the NERC Reference Reserve Margin Level definition.

[16] A 50/50 demand forecast is defined as a demand forecast adjusted to reflect normal weather that is projected on a 50-percent probability basis, *i.e.*, a peak demand forecast level which has a 50 percent probability of being under or over achieved by the actual peak demand.

[17] 2010/2011 Winter Actual Demand is not weather normalized

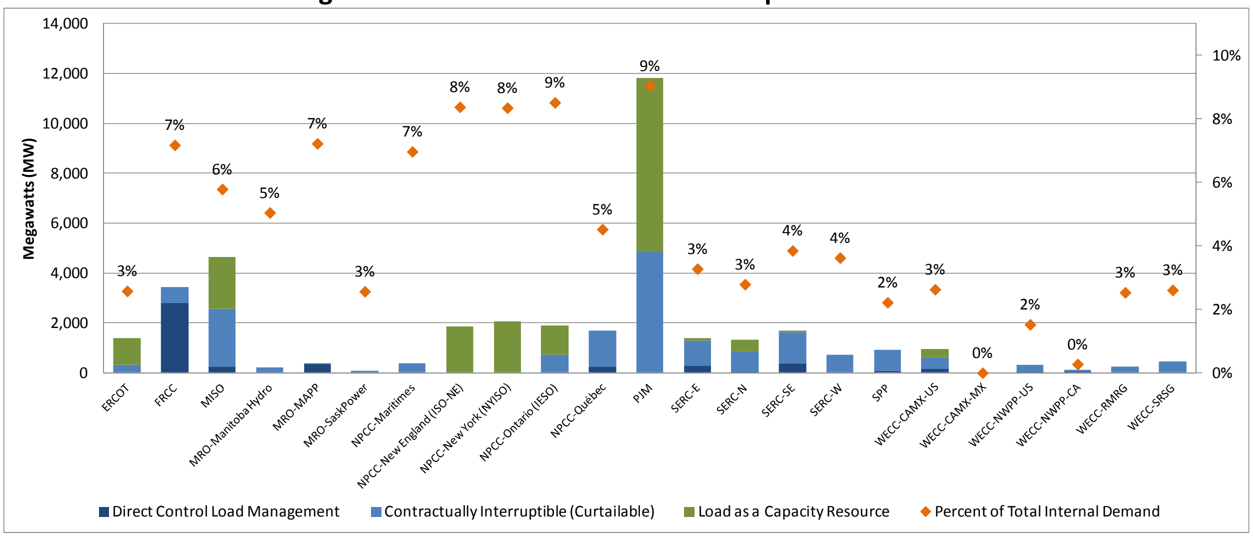
[18] See the *PJM Self Assessment* on page 119 for more information the integration of these stakeholders into the PJM footprint.

[19] This non-coincident value for all Assessment Areas generally occurs in the month of January 2012

peak.[20] This represents an increase of 0.3 percent over 2010/2011 projected Total Internal Demand this winter season.[21]

Another factor affecting peak demand forecasts is the amount of New Energy Efficiency and Demand Response contributing to peak demand reduction. Economic factors and Regional, state, or provincial Demand Response initiatives can greatly increase or decrease the amount (*i.e.,* capacity) of Demand Response available to system operators to manage peak demand. Demand Response programs for this winter total 37,945 MW for all NERC assessment areas. Figure 4, below, shows Demand Response product categories available for deployment during the 2011/2012 winter season along with the Percent of Total Internal Demand they represent in each assessment area.

Figure 4: Winter On-Peak Demand Response Forecast



Weather Forecast

United States

For the second consecutive winter season, 2010/2011 and now 2011/2012, La Niña[22,23] will influence weather patterns across the United States. With La Niña in place, National Oceanic and Atmospheric Administration (NOAA) in the U.S. forecasts that areas in Texas, Oklahoma, New Mexico and parts of surrounding states are unlikely to get enough rain to alleviate the ongoing drought in the Southwestern U.S. Texas is at the epicenter of the current drought and has just experienced its driest 12-month period on record from October 2010 through September 2011. The NOAA seasonal outlook does not project where and when snowstorms may hit or provide total seasonal snowfall accumulations. Snow forecasts are dependent upon winter storms, which are generally not predictable more than a week in advance.

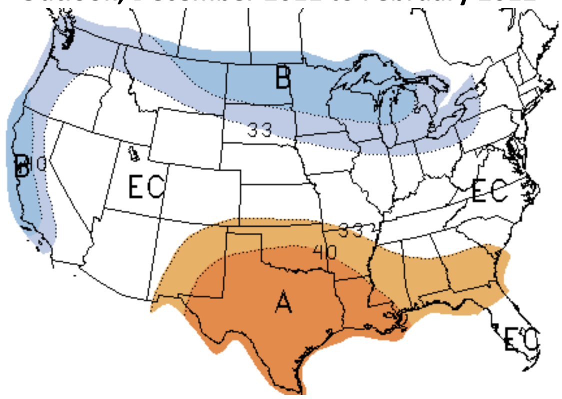
[20] This MW value of Demand Response represents the Total Dispatchable, Controllable Demand Response value submitted by Assessment Areas

[21] 2010/2011 Winter Forecast Total Internal Forecast Demand was 736,568MW

[22] La Niña is associated with cooler than normal water temperatures in the tropical Pacific Ocean and influences weather throughout the world.

[23] La Niña, meaning the little girl, names the appearance of cooler than normal waters in the eastern and central Pacific Ocean. Sometimes called El Viejo, anti-El Niño, or simply "a cold event", it is the antithesis of El Niño.

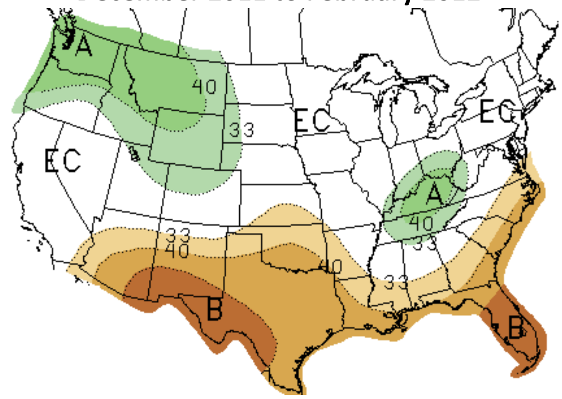
Figure 5: U.S. Winter Mean Temperature Outlook, December 2011 to February 2012



Source: NOAA

A (Orange)	Above-Normal Temperatures Forecast
EC (White)	Equal Chance of Above- or Below-Normal Temperatures
B (Blue)	Below-Normal Temperatures Forecast

Figure 6: U.S. Winter Mean Precipitation Outlook, December 2011 to February 2012



Source: NOAA

A (Green)	Above-normal Precipitation Forecast
EC (White)	Equal Chance of Above- or Below-Normal Precipitation
B (Brown)	Below-Normal Precipitation Forecast

According to the U.S. Winter Outlook[24] (December through February) the forecast for each area within the U.S. is the following:

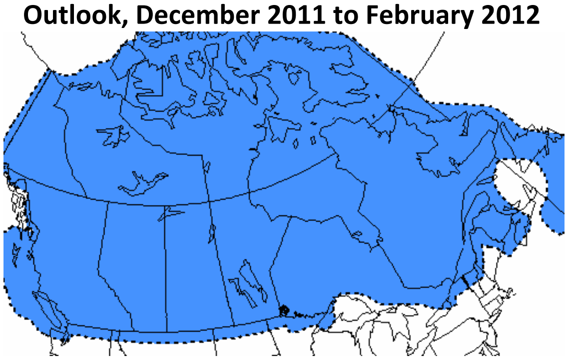
- **Pacific Northwest**: colder and wetter than average. La Niña often results in below-average temperatures and increased mountain snow in the Pacific Northwest and western Montana during the winter months. This may set the stage for spring flooding in the Missouri River Basin;
- **California**: colder than average and wetter than average conditions in northern California and drier than average conditions in southern California. All of the southern part of the nation is at risk of having above normal wildfire conditions starting this winter and lasting into the spring;
- **Northern Plains**: colder and wetter than average. Spring flooding could be a concern in parts of this region;
- **Southern Plains and Gulf Coast States**: warmer and drier than average. This will likely exacerbate drought conditions in these regions;
- **Florida and south Atlantic Coast**: drier than average, with an equal chance for above-, near-, or below-normal temperatures. Above normal wildfire conditions;
- **Ohio and Tennessee Valleys**: wetter than average with equal chances for above-, near-, or below-average temperatures. Potential for increased storminess and flooding;
- **Northeast and Mid-Atlantic**: equal chances for above-, near-, or below-normal temperatures and precipitation. Winter weather for these regions is often driven not by La Niña but by the Arctic oscillation. If enough cold air and moisture are in place, areas north of the Ohio Valley and into the Northeast could see above-average snow;
- **Great Lakes**: colder and wetter than average;

[24] The 2011/2012 Winter Weather Outlook was published by NOAA in October 2011: http://www.noaanews.noaa.gov/stories2011/20111020_winteroutlook.html

Canada

The development of La Niña pattern shows considerable fluctuations in the weather pattern in Canada; however, most La Niña winters tend to be colder and snowier than normal, particularly in western Canada. The 2011/2012 winter forecast does not deviate from that trend, forecasting below normal temperatures for all NERC areas in Canada, and forecasting above normal precipitation in areas of Southwest Canada (Alberta, Saskatchewan, and Manitoba), central Ontario, and Northeast Canada (New Brunswick, Nova Scotia, and portions of northeast Québec). The official 2011/2012 Winter Forecast by Environment Canada is traditionally released after the publication of this report (typically on November 30), with the data presented below reflecting the most current three month ahead forecast issued.

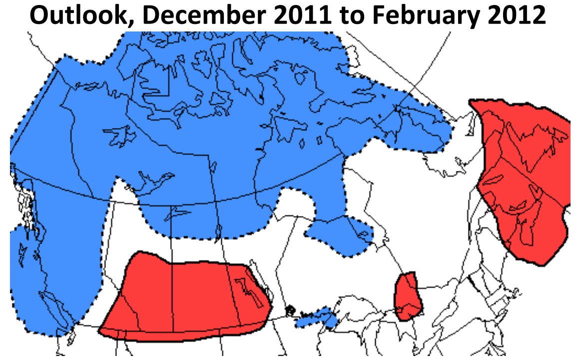
Figure 7: Canada Winter Mean Temperature Outlook, December 2011 to February 2012



Source: Environment Canada

Red	Above-Normal Temperatures Forecast
White	Equal Chance of Above- or Below-Normal Temperatures
Blue	Below-Normal Temperatures Forecast

Figure 8: Canada Winter Mean Precipitation Outlook, December 2011 to February 2012



Source: Environment Canada

Red	Above-normal Precipitation Forecast
White	Equal Chance of Above- or Below-Normal Precipitation
Blue	Below-normal Precipitation Forecast

Operational Issues

Response to February 2010/2011 Cold Weather Events

During the week of February 1-5, 2011, the Southwestern area of the United States experienced unusually cold weather that resulted in the widespread loss of service to electric and gas customers. Within the Texas Interconnection, record-breaking winter demand levels were experienced on two different occasions as temperatures hit twenty year lows in the region. A portion of the Western Interconnection also experienced unusual, sub-freezing temperatures during this period, and these cold temperatures also extended into the Southwest Power Pool region within the Eastern Interconnection.

Over 3.7 million electric utility consumers were affected during this time period, as utilities were forced to initiate rolling blackouts of over 6,000 MW to maintain the reliability of the bulk power system.

A joint Report issued by FERC and NERC in August 2011[25] addressed the load shedding and curtailments experienced during the event, along with identifying causes of the outages and supply disruptions, electric and natural gas interdependencies, and identified key findings and recommendations. Separately, NERC issued a report in September 2011[26] which analyzed how the electrical system performed during the period of extended cold weather. Additionally, performance of the system was determined by analyzing system simulations completed by NERC Staff to review the impacts in the El Paso, New Mexico, and Arizona on an individual company basis, and frequency response performance of the Eastern, Western, and Texas Interconnections. The findings in both the joint FERC-NERC report issued in August 2011 and the NERC report issued in September 2011 are aligned and complementary.

The recommendations from the FERC/NERC Report are reprinted in Appendix I for consistency and relevancy to the 2011/2012 winter season, summarized by type below (Table 4).

Table 4: FERC/NERC Report Recommendations by Area

Recommendations Type	Number of Recommendations Issued
Planning and Reserves Management	5
Coordination with Generator Owner/Operators	5
Winterization of Assets	1
Plant Design	2
Maintenance / Inspection of Assets	7
Communications	2
Load Shedding	4
Total Recommendations Issued	**26**

The NERC System Analysis report on the February 2011 event[27] identified a number of important Conclusions and Recommendations for the electric industry. The conclusions of this analysis, conducted by NERC staff, and released in September 2011, can be found in Appendix II.

At this time, there are several state level initiatives underway to address the recommendations issued in August 2011 joint report by FERC and NERC. The Salt River Project has made infrastructure and enhanced operational procedures to more robustly address unusual and prolonged cold weather. The staff of the New Mexico Public Utilities Commission is in the final drafting stages of a report that will included recommendations for weatherization and other recommended infrastructure improvements. In Texas, the Texas Public Utility Commission has directed electric utilities to update their emergency operating plans and recommended improvements to operating and planning procedures in a number of areas.[28] FERC has also issued recommendations to the natural gas industry which highlight the need for

[25] Joint FERC / NERC Report on Cold Weather Outages in the Southwest United States (August 2011): http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

[26] NERC Report on Electrical System performance on Cold Weather Outages in Southwest United States (September 2011) http://www.nerc.com/files/RISA%20Cold%20Snap%20report%20September%202011.pdf

[27] NERC Report on Electrical System performance on Cold Weather Outages in Southwest United States (September 2011) http://www.nerc.com/files/RISA%20Cold%20Snap%20report%20September%202011.pdf

[28] Texas Reliability Entity (TRE) Report to the Public Utility Commission of Texas (PUCT) on February 2, 2011 Outages http://www.puc.state.tx.us/agency/topic_files/TX_RE_EEA_Protocol_Comp_Report.pdf

all levels of government (state, local, and federal) to work in partnership with the natural gas industry to determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities.[29,30]

ERCOT released a report[31] in October 2011 by its Technical Advisory Committee[32] that included six recommendations regarding seasonal assessments, operational communications, further technical investigation, load shedding, and other operational issues to be further examined by ERCOT and its members. The Public Utilities Commission of Texas will be further investigating the cold snap with Project No. 39646 - PUC Report on Extreme Weather Preparedness Best Practices". ERCOT has also begun a number of Task Forces[33],[34] to address the issues of winter events and several Regional Market Rules have been modified, while others are still pending.[35] Additionally, Texas Reliability Entity (TRE) continues to review the information and act according to its delegation agreement with NERC. Several lessons learned have already been provided to the industry as a result of the events of last year.[36]

El Paso Electric (EPE) commissioned Black & Veatch,[37] to complete a cold weather assessment of its generation facilities. The resulting report made a number of recommendations that EPE modify and upgrade to existing generation facilities to facilitate continuous and reliable operation during periods of extreme cold weather as experienced in February 2011.[38]

Entities in the SPP RTO footprint operate in winter weather conditions every year and make preparations in advance of these conditions. Winter preparation varies by entity and generating unit type, but typically begins in the fall season.[39] One area particular concern, the need in the SPP region to identify the feeders that natural gas supply or processing facilities reside, was identified during the

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[29] Recommendations – Natural Gas , Number 1, page 214: Joint FERC / NERC Report on Cold Weather Outages in the Southwest United States (August 2011): http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

[30] Key Finding Number 1, page 212, FERC / NERC Joint FERC / NERC Report on Cold Weather Outages in the Southwest United States: Extreme low temperatures and winter storm conditions resulted in a widespread wellhead, gathering system, and processing plant freeze-offs and hampered repair and restoration efforts, reducing the flow of gas in production basins in Texas and New Mexico by between 4 Bcf and 5 Bcf per day, or approximately 20 percent, a much greater extent than in the past. http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

[31] ERCOT Technical Advisory Committee Report on February 2, 2011 Outages http://www.ercot.com/content/meetings/board/keydocs/2011/1018/Item_07b_-_TAC_Report_Related_to_February_Event_Analysis.pdf

[32] The TAC is a subcommittee in the ERCOT governance structure reporting to the Board of Directors as defined by the ERCOT bylaws

[33] http://www.ercot.com/content/meetings/board/keydocs/2011/0322/Item_06a_-_Board_Task_Force_on_Operations_Report.pdf

[34] http://www.ercot.com/content/meetings/board/keydocs/2011/0322/Item_06b__Report_on_Feb._2_Rotating_Outages_Communications_.pdf

[35] ERCOT Nodal Protocol Revision Requests (NPRR) 315, 356, 365, 369, and 394 include changes based on February 2011 Cold Weather event. ERCOT NPRR can be reviewed at http://www.ercot.com/mktrules/nprotocols/nprr

[36] Texas Reliability Entity, Inc. monitors and enforces compliance with reliability standards for the North American Electric Reliability Corporation; develops regional standards; and monitors and reports on compliance with the ERCOT Protocols. http://www.texasre.org

[37] Cold Weather Protection Assessment Report Press Release, June 2011, http://www.epelectric.com/about-el-paso-electric/cold-weather-protection-assessment-report

[38] Black & Veatch Report on El Paso Electric http://www.epelectric.com/files/html/Storm_2011/B_V_Report_Rev_0.pdf

[39] This typically includes: includes inspection of freeze protection equipment and winterization of various generator components such as pump houses and cooling towers.

February 1-5 event, as removing these facilities during rolling blackouts may exacerbate natural gas supply issues in the region and impact the reliability of the bulk power system.[40]

Additionally, on November 9, 2011, FERC's Office of Electric Reliability requested a status update on the implementation of recommendations from the joint FERC/NERC report from Chief Executive Officers at SPP Regional Entity, Texas Reliability Entity, and the Western Electricity Coordinating Council (WECC).[41] Responses from this request are due to FERC no later than December 9, 2011.

2011/2011 Winter Drought Forecast

Monitoring drought conditions has become an integral part of planning, preparedness and drought mitigation efforts at the national, regional and local levels. Drought conditions can develop in all regions of the North American continent, and can have impacts to a number of areas of the electric industry. Since 1980, major droughts and heat waves within the U.S. alone have resulted in costs exceeding $100 billion (US) dollars.[42] NERC continues to monitor drought conditions and tracking their impact on reliability.

North America

The North America Drought Monitor (NADM)[43] is a cooperative effort between drought experts in Canada, Mexico and the United States to monitor drought across the continent on an ongoing basis. Figure 9 below, reflects current conditions throughout the North American Continent with respect to Drought. Areas of concern continue exist in Southwestern and Southeastern United States. The expected continuation of the near-record drought in Texas threatens the availability of sufficient generation for the ERCOT area, particularly if extreme weather leads to above-normal demands. NERC, TRE, and ERCOT will continue to monitor this situation to ensure reliability is not affected.

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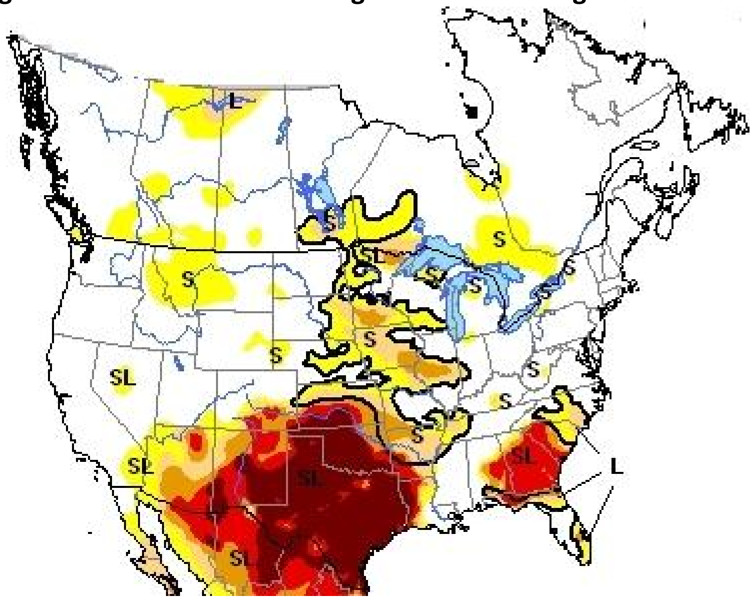
40 More information, see page 204 *FERC/NERC Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5* http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

41 November 9, 2011 Letter from Joe McClelland, Director of FERC's Office of Electric Reliability: http://elibrary.ferc.gov:0/idmws/doc_info.asp?document_id=13970081

42 Lott, N., and T. Ross, 2000. NCDC Technical Report 2000-02, A Climatology of Recent Extreme Weather and Climate Events. [Asheville, N.C.]: National Climatic Data Center.

43 Major US participants in the NADM program include NOAA's National Climatic Data Center, NOAA's Climate Prediction Center, the US Department of Agriculture, and the National Drought Mitigation Center. Major participants in Canada and Mexico include Agriculture and Agrifood Canada, the Meteorological Service of Canada, and the National Meteorological Service of Mexico (SMN - Servicio Meteorologico Nacional). http://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/

Figure 9: North American Drought Monitor through October 2011



Source: NOAA

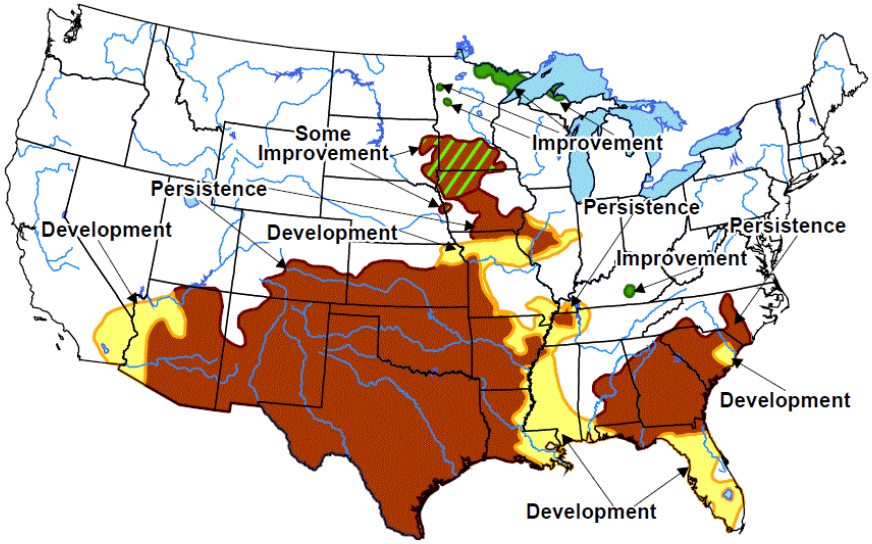
Drought Intensities				
D0 (Yellow)	D1 (Light Brown)	D2 (Orange)	D3 (Red)	D4 (Burgundy)
Abnormally Dry	Drought – Moderate	Drought – Severe	Drought – Extreme	Drought – Exceptional

United States

The U.S. Drought Monitor[44] forecast for October 2011 through January 2012 expects severe drought conditions in the Southwestern and Southeastern United States to persist and possibly intensify during the 2011/2012 winter season. Additionally, drought conditions are expected to develop in other areas of the Southeastern United States, including states such as Florida, Louisiana, Mississippi, and South Carolina. Desert portions of the Southwest, including areas in southeastern California and western Arizona are expected to develop drought like conditions as well.

[44] The U.S. Drought Monitor is a Product of National Drought Mitigation Center and is available at: http://droughtmonitor.unl.edu/

Figure 10: United States Winter Drought Forecast[45]
(October 2011 through January 2012)



Brown	Brown and Green	Green	Yellow
Drought to Persist or Intensify	Drought Ongoing, Some Improvement	Drought Likely to improve, impacts ease	Drought Development Likely

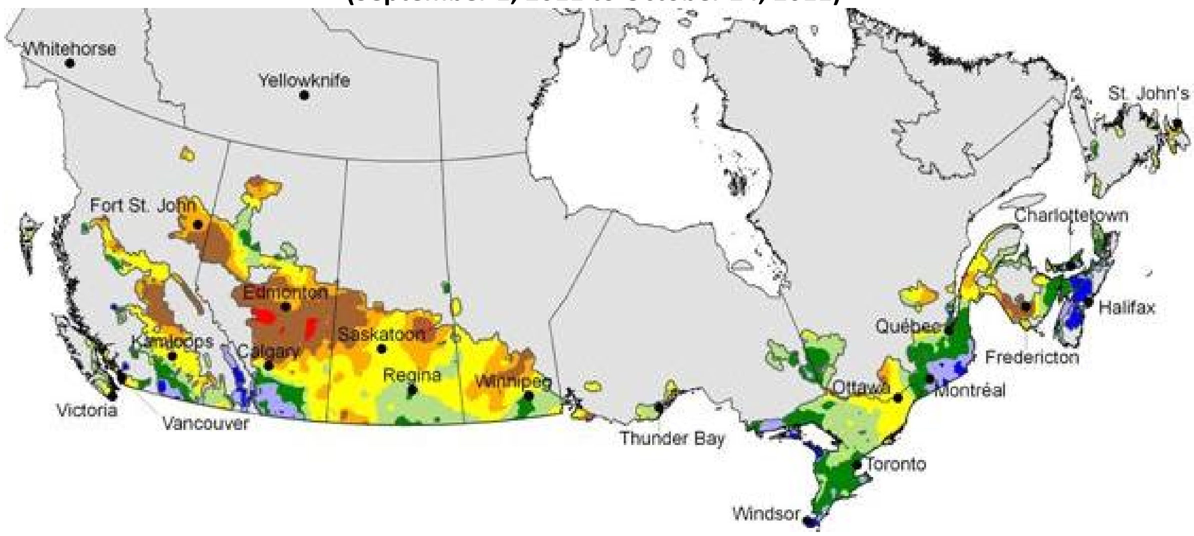
Canada

Agriculture and Agri-Foods Canada[46] maintains the drought monitoring technology for Canada. Their most recent drought monitoring release of October 24, 2011 shown in Figure 11) indicates a number of areas with significant variation from historical distribution of precipitation, with a number of areas experiencing recording higher than average amounts. Areas that contain hydro resources used for electricity generation, such as province of Québec, have recorded higher than normal rainfall amounts. As of today, there are no forecasted impacts to electric reliability due to drought in Canada.

[45] The U.S. Drought Forecast is a Product of the NOAA/ National Weather Service National - Centers for Environmental Prediction - Climate Prediction Center http://www.cpc.ncep.noaa.gov/products/expert_assessment/seasonal_drought.html

[46] Agriculture and Agri-Food Canada (AAFC) provides information, research and technology, and policies and programs to achieve an environmentally sustainable agriculture, agri-food and agri-based products sector, a competitive agriculture, agri-food and agri-based products sector that proactively manages risk, and an innovative agriculture, agri-food and agri-based products sector. http://www.agr.gc.ca/index_e.php

Figure 11: Precipitation Compared to Historical Distribution[47]
(September 1, 2011 to October 24, 2011)



Source: Agriculture and Agri-Foods Canada, October 2011

Record Dry	High
Extremely Low	Very High
Very Low	Extremely High
Low	Record Wet
Mid-Range	——Extent of Agricultural Land

Fuel Supply Analysis

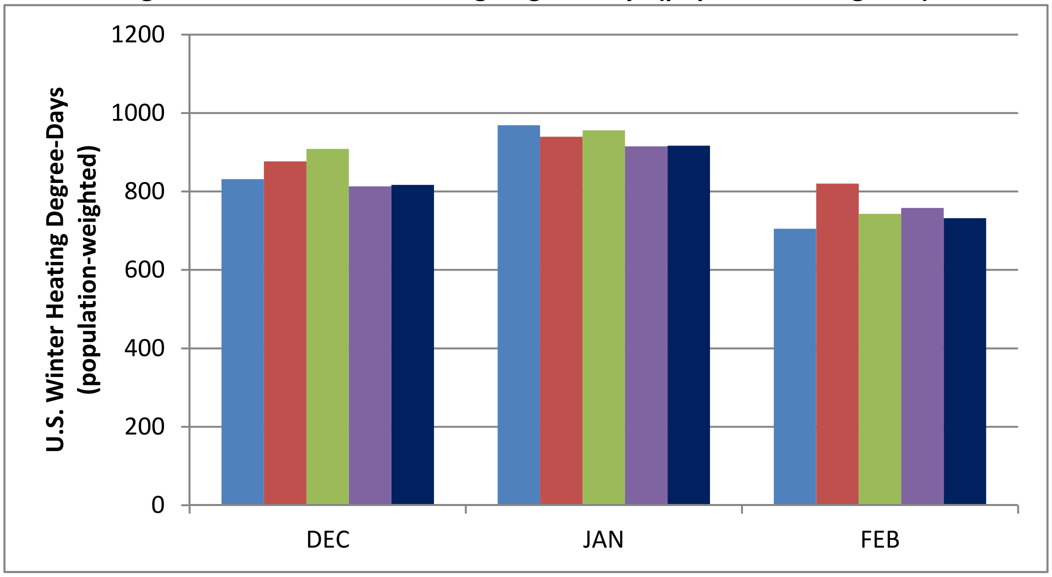
The National Oceanic and Atmospheric Administration's (NOAA)[48] most recent climate projection, released on October 19, 2011, forecasted the number of heating degree-days[49] to be two (2) percent warmer during the October through March heating season compared with last winter. The number of heating degree-day projections by NOAA vary widely among regions within the United States, with the West projected to be about three percent colder than last winter, and areas in the South United Stated projected to be about five percent warmer. Figure 12 below shows the prior degree heating days per month for the past three winter seasons, including a projection (based on the NOAA data) for the 2011/2012 winter season, along with number of normal degree heating days .

[47] This map is available from Agriculture and Agri-Foods Canada http://www4.agr.gc.ca/resources/prod/doc/pfra/maps/nrt/nl_ay_pe_s_e.pdf

[48] The U.S. Winter Heating Degree Days is a Product of the NOAA/ National Weather Service National - Centers for Environmental Prediction - Climate Prediction Center: http://www.cpc.ncep.noaa.gov/pacdir/DDdir/ddforecast.txt

[49] The number of degrees that a day's average temperature is below 65 degrees Fahrenheit (or 18 degrees Celsius). Temperatures below 65 degrees Fahrenheit are the days in which buildings need to be heated. For example, if the day's average temperature over 24 hours (0:00 to 23:59) is 50 degrees Fahrenheit, its Heating Degree Day (HDD) is 15.

Figure 12: U.S. Winter Heating Degree-Days (population-weighted)



Source: U.S. Energy Information Administration, October 2011[50]

2008/2009	The number of Winter Heating Degree-Days from Dec 2008 thru Feb 2009
2009/2010	The number of Winter Heating Degree-Days from Dec 2009 thru Feb 2010
2010/2011	The number of Winter Heating Degree-Days from Dec 2010 thru Feb 2011
2011/2012	The FORECAST number of Winter Heating Degree-Days for Dec 2011 thru Feb 2012
Average	The normal number of Winter Heating Degree-Days for the winter season

All NERC assessment areas do not expect any fuel deliverability issues for the 2011/2012 winter season at this time. The increased reliance on natural gas[51] as one of the leading fuels used for both intermediate and peaking capacity has prompted NERC to study the interdependencies that exist between the natural gas industry and the electric industry. The first report, the *2011 Special Reliability Assessment: A Primer on the Natural Gas and Electric Power Interdependency in the United States* was published by NERC in November 2011.[52]

Natural Gas

Natural gas working inventories, ending on September 30, 2011, showed a storage value of 3.4 trillion cubic feet (Tcf). This storage value is approximately 2.6 percent, or 91 billion cubic feet (Bcf), below the reported September 30, 2010 natural gas storage level. The U.S. Energy Information Administration (EIA) projects that working natural gas inventory storage levels will approach last year's high levels by the end the injection season, which typically ends at the end of October each year. Figure 13 below, shows the historical data of working natural gas storage levels from January 2007 through September 2011, with a forecast range from October 2011 through December 2012.

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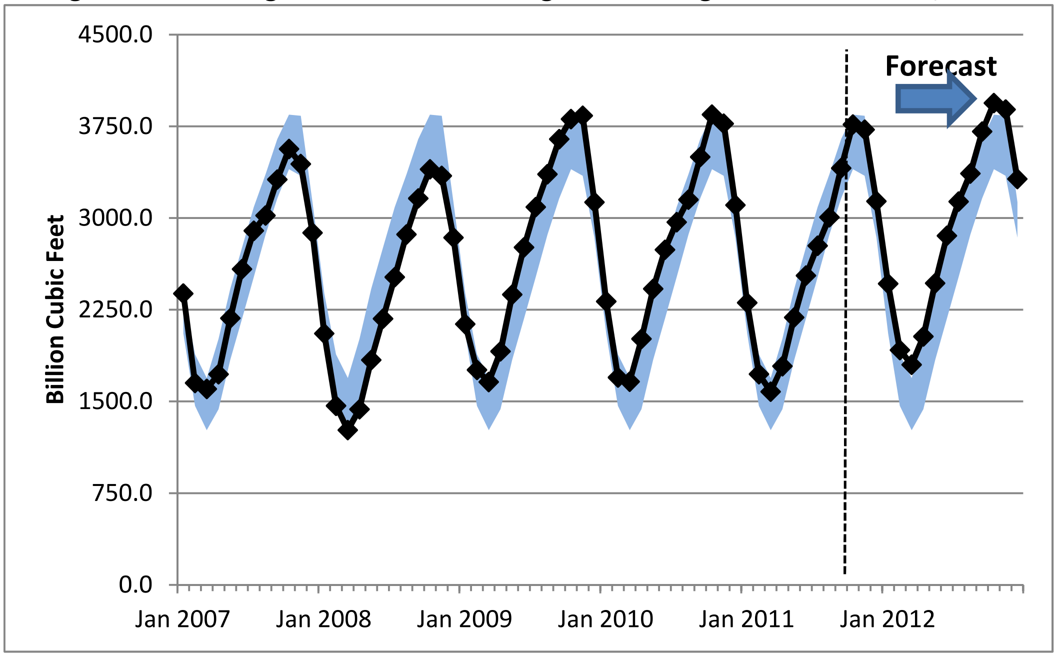
[50] The U.S. Energy Information Administration Short Term Energy Outlook is the source for this data: http://205.254.135.24/steo/

[51] The 2011 NERC Long Term Reliability Assessment identifies 37.7% of 2011 Generation Resources have Gas as their primary driver. The final report is available here: http://www.nerc.com/files/2011LTRA_Final.pdf.

[52] The *2011 Special Reliability Assessment: A Primer on the Natural Gas and Electric Power Interdependency in the United States*, December 2011: http://www.nerc.com/page.php?cid=4|61.

Figure 13: Working Natural Gas in Underground Storage as of October 31, 2011



Source: U.S. Energy Information Administration, October 2011[53]

Blue Area	Month-End Natural Gas Storage Range (High and Low Data points for each month)
Black Line	Month-End Natural Gas in Storage (Actual and Projected)

The U.S. EIA forecasts marketed natural gas production to average approximately 66 Billion cubic feet per day (Bcf/d) in 2011, a 4.2 Bcf/d (6.7 percent) increase over 2010 levels. The entirety of this growth in production of Natural Gas is due to increases in production in the Lower 48 states. EIA also forecasts that overall production will continue to grow in 2012, but at a slower pace, increasing at an average rate of 1.4 Bcf/d (2.1 percent), to an average natural gas production rate of approximately 67.4 Bcf/d.

Coal Stocks

Full year coal production (January through December) in the U.S. Lower 48 states is expected to fall by approximately 1.5 percent in 2011 versus 2010 (through September 2011 production values). This reported decline in coal production also accounts for a significant increase in coal production that is bound for export to foreign markets in 2011. Coal production and usage should not be an issue for U.S. Electric Power generators owners and operators during the 2011/2012 winter season, as adequate supply is available for delivery and consumption. Figure 14below shows the monthly range of U.S. coal stocks (high and low values as reported to EIA) and the stock of coal at U.S. electric power plants. All values on this chart are represented in million short tons.[54]

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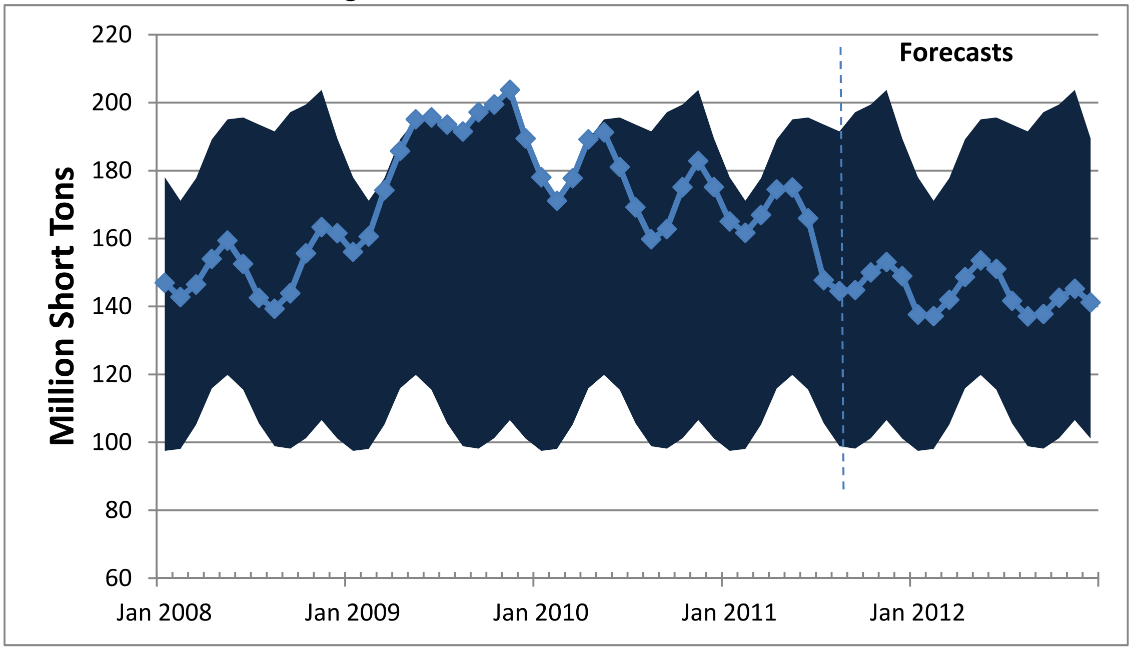
[53] The U.S. Energy Information Administration Short Term Energy Outlook is the source for this data: http://205.254.135.24/steo/.

[54] The short ton is a unit of mass equal to 2,000 pounds (907.18474 kilograms).

Figure 14: US Electric Power Coal Stocks



Source: Energy Information Administration, October 2011[55]

Navy Area	Monthly Range of United States Coal Stocks
Blue Line	United States Electric Power Coal Stocks

Nuclear Generation

The events at Tokyo Electric's Fukushima-Daiichi nuclear power plant in Japan following the March 11, 2011 earthquake and resulting tsunami caused heightened public concern about the vulnerabilities of nuclear power facilities in the United States and Canada. The Nuclear Regulatory Commission (NRC), the United States federal agency responsible for ensuring nuclear plant, created a task force to specifically investigate issues that developed from the event.

In a report issued July 2011,[56] the NRC Japan Task Force proposed improvements in areas ranging from loss of power due to earthquakes, flooding, spent fuel pools, venting and preparedness, and said a "patchwork of regulatory requirements" developed "piece-by-piece over the decades" should be replaced with a "logical, systematic and coherent regulatory framework" to further bolster reactor safety in the United States.[57]

On October 20, 2011,[58] the NRC directed the agency's staff to begin immediately implementing seven safety recommendations from the NRC's Near-Term Task Force on lessons learned from the reactor accident at Fukushima. The seven recommendations are among 12 comprehensive safety recommendations presented by the Task Force to the Commission in July 2011, and cover issues including the loss of all A/C electrical power at a reactor (also called "station blackout"), reviews of

[55] The U.S. Energy Information Administration Short Term Energy Outlook is the source for this data: http://205.254.135.24/steo/.

[56] Recommendations for Enhancing Reactor Safety in the 21st Century: http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf.

[57] NRC News Release, No. 11-127, July 13, 2011: http://www.nrc.gov/reading-rm/doc-collections/news/2011/11-127.pdf.

[58] NRC News Press Release, No. 11-202, October 20, 2011: http://pbadupws.nrc.gov/docs/ML1129/ML11293A030.pdf.

seismic and flooding hazards, emergency equipment and plant staff training. The remaining Task Force recommendations, along with the additional recommendations, are currently pending with the Commission.[59]

On August 23, 2011 central Virginia experienced a magnitude 5.8 earthquake on the Richter Scale[60] with the epicenter in Mineral, Virginia, a few miles from the North Anna Nuclear Power Plant[61] operated by Dominion Virginia Power. The plant safely shut down as designed and was powered by diesel generators for a few hours on August 23, 2011. The NRC monitored the situation, observed plant inspections and performed assessments of quake data. On August 29, 2011 the NRC dispatched an Augmented Inspection Team to the plant to further review the effects of the earthquake, the operators' response, and the plant staff's activities to check equipment. The NRC, working extensively with Dominion Virginia Power, will ensure the plant is capable of continuing to operate safely before the agency authorizes restart of the reactors.

59 Areas to be the top priorities include: Seismic and flood hazard re-evaluations; Station Blackout (loss of off-site power and on-site emergency power) regulatory actions; assessments to ensure there are reliable hardened vents for Mark I and II containments; and spent fuel pool instrumentation.

60 The Richter magnitude scale was developed in 1935 by Charles F. Richter of the California Institute of Technology as a mathematical device to compare the size of earthquakes. The magnitude of an earthquake is determined from the logarithm of the amplitude of waves recorded by seismographs. http://earthquake.usgs.gov/learn/topics/richter.php.

61 The North Anna Nuclear Power Plant generates 1,806 megawatts from two units. Unit 1 began commercial operation in June 1978 and Unit 2 followed in December 1980. http://dom.com/about/stations/nuclear/north-anna/index.jsp.

Projected Demand, Resources, and Reserve Margins

Demand

NERC uses the following terms to categorize on-peak electricity demand:

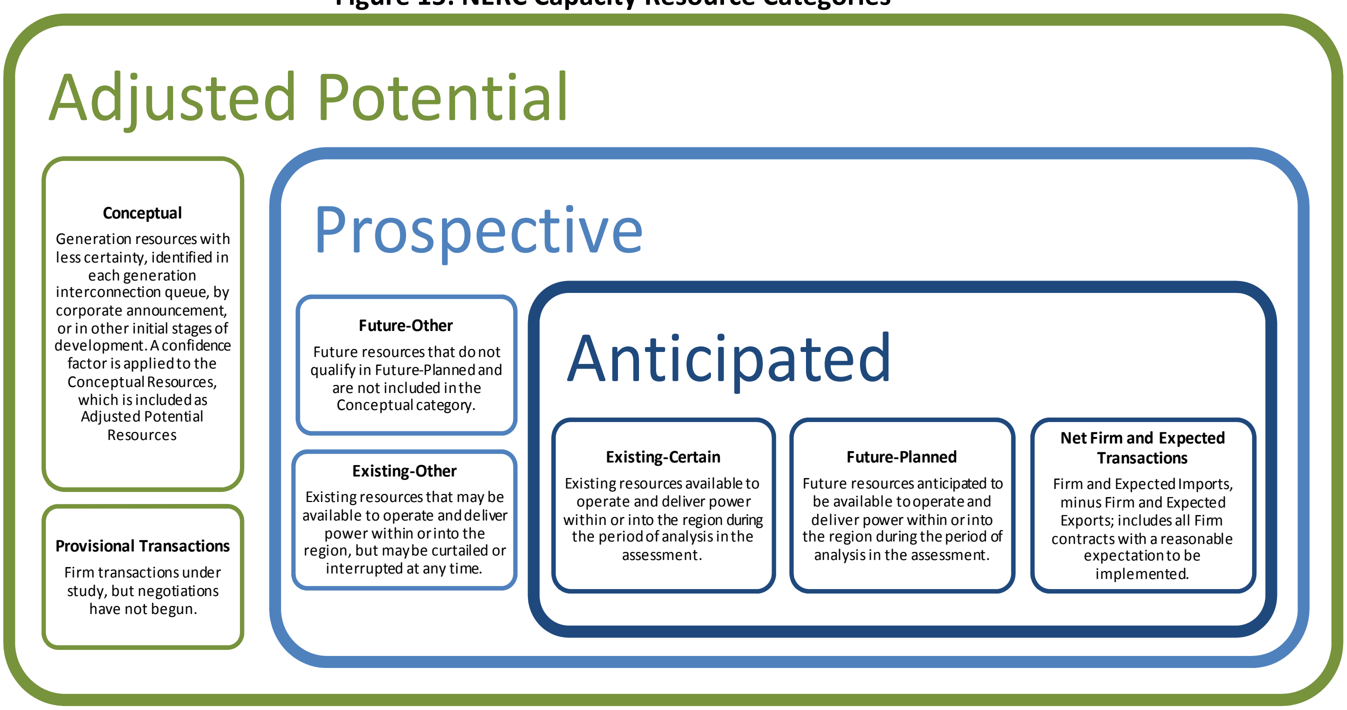
Total Internal Demand — The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.

Net Internal Demand (MW) — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

Capacity Resources

NERC uses the following terms to categorize capacity resources and transactions throughout this report. These capacity categories are then used to calculate estimated Planning Reserve Margins for each NERC Assessment Area (Figure 15).

Figure 15: NERC Capacity Resource Categories[62]



62 See section entitled *Reliability Concepts Used in this Report* for more detailed definitions.

Reserve Margins

Planning Reserve Margins, developed for this analysis, are categorized based on certainty that future resources expected to be available to delivery power within the assessment time frame are actually constructed and deployed. A consistent method of calculating Reserve Margins (initially introduced in the *2011 Summer Reliability Assessment*) will be used in this assessment and in subsequent NERC reports. This accurately accounts for Controllable Capacity Demand Response (CCDR) as a supply-side resource.[63] A comparison of the pre-2011 to the revised method is presented below (Table 5).

Table 5: Enhancements to Reserve Margin Calculations (Pre-2011 vs. 2011)

Pre-2011 Reserve Margin Calculation (Majority)	2011 Reserve Margin Calculation
$RM = \frac{\text{[(Capacity - (Total Internal Demand - CCDR)]}}{\text{(Total Internal Demand - CCDR)}}$	$RM = \frac{\text{[(Capacity + CCDR) - (Total Internal Demand)]}}{\text{(Total Internal Demand)}}$

Reserve Margins are capacity-based metrics and do not provide a comprehensive assessment of performance in energy-limited systems (*e.g.,* hydro capacity with limited water resources or systems with significant variable generation). Each capacity resource category (identified and explained in the previous section) is also used to calculate each different planning Reserve Margin. Consider the following examples (Table 6).

Table 6: Anticipated, Prospective, and Adjusted Potential Reserve Margin Calculations

Reserve Margin	Calculation
Anticipated	$RM = \frac{\text{[(}\textbf{Anticipated Capacity Resources}\text{) - (Total Internal Demand - CCDR)]}}{\text{(Total Internal Demand)}}$
Prospective	$RM = \frac{\text{[(}\textbf{Prospective Capacity Resources}\text{) - (Total Internal Demand - CCDR)]}}{\text{(Total Internal Demand)}}$
Adjusted Potential	$RM = \frac{\text{[(}\textbf{Adjusted Potential Capacity Resources}\text{) - (Total Internal Demand - CCDR)]}}{\text{(Total Internal Demand)}}$

Planning Reserve Margins for each Assessment Area are compared to the NERC Reference Margin Level (Target) which is usually defined and provided by each NERC Region or subregion. In the absence of a defined Reserve Margin Target, NERC assigns a 15 percent Reserve Margin Target for predominately thermal systems and 10 percent for predominately hydro systems. This Target then serves as a bass for determining whether more resources (*e.g.,* generation, Demand-Side Management, transfers) may be needed within that Region/subregion.

[63] This change was recommended by the NERC Resources Issues Subcommittee under the direction of the NERC Planning Committee. The recommendation was approved by the NERC Planning Committee in 2010 and is detailed in the report titled *Recommendations for the Treatment of Controllable Capacity Demand Response programs in Reserve Margin Calculations,* June 2010: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

Figure 16: NERC Reserve Margin Example

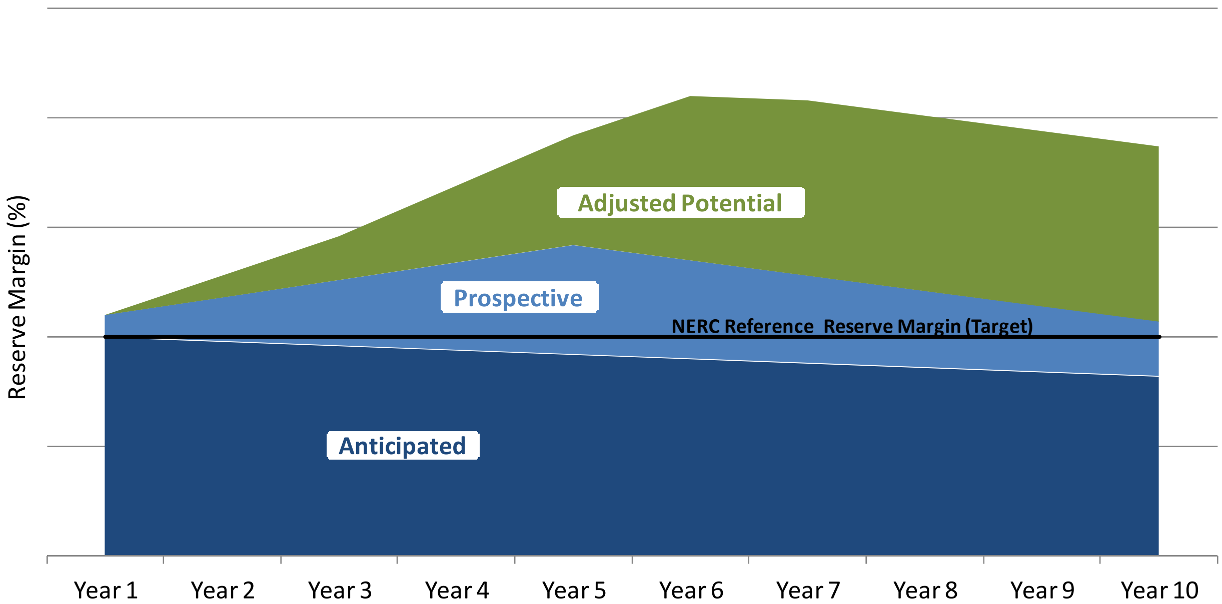


Table Notes

Note 1: Projected Reserve Margins for the 2011/2012 winter, are shown on the following pages (Table 7 through Table 10). The following notes provide additional clarification.

Note 2: Demand and Supply forecasts were reported between February and August, 2011—depending on the Assessment Area.

Note 3: Values for both Total Internal Demand and Net Internal Demand for each Assessment Area represent on-peak projections for the given season.

Note 4: For seasonal assessments, WECC is divided into four subregions, based on Reserve Sharing Groups (RSG) with similar demand patterns and operating practices. WECC provides more granular subregional divisions for NERC's *Long-Term Reliability Assessments*.

Note 5: The winter demand data collected for this seasonal assessment and reflected in the following tables may be slightly different when compared to the NERC *2011 Long-Term Reliability Assessment* (to be published shortly before the release of this report) due to the timing of data collection for each assessment.

Table 7: Demand, Resources, and Reserve Margins –2011/2012 Winter Seasonal Peak Forecast

Assessment Area / Country / NERC Interconnection	Demand		Capacity Resouces			Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Existing Certain and Net Firm Transactions (MW)	Anticipated (MW)	Prospective (MW)	Existing Certain and Net Firm Transactions (%)	Anticipated (%)	Prospective (%)	NERC Reference Margin Level (%)
ERCOT	53,303	51,929	72,995	73,038	73,038	36.9%	37.0%	37.0%	13.75%
FRCC	47,613	44,196	59,403	59,203	59,151	24.8%	24.3%	24.2%	15.0%
MISO	79,994	75,363	110,507	110,767	125,593	38.1%	38.5%	57.0%	15.0%
MRO-MAPP	5,036	4,672	6,725	6,727	6,727	33.5%	33.6%	33.6%	15.0%
NPCC-New England (ISO-NE)	22,255	20,391	32,299	32,299	32,308	45.1%	45.1%	45.2%	15.0%
NPCC-New York (NYISO)	24,533	22,651	36,194	37,176	39,711	47.5%	51.5%	61.9%	15.5%
PJM	130,711	118,885	193,492	194,458	188,712	48.0%	48.8%	44.4%	15.0%
SERC-E	42,459	41,067	54,310	54,109	54,109	27.9%	27.4%	27.4%	15.0%
SERC-N	47,123	45,808	57,401	57,401	57,415	21.8%	21.8%	21.8%	15.0%
SERC-SE	44,259	42,555	65,962	65,962	68,350	49.0%	49.0%	54.4%	15.0%
SERC-W	19,931	19,208	36,944	36,836	38,870	85.4%	84.8%	95.0%	15.0%
SPP	41,089	40,178	65,344	65,372	68,700	59.0%	59.1%	67.2%	13.6%
WECC-CAMX-US	36,560	35,598	54,970	55,003	55,003	50.4%	50.4%	50.4%	11.0%
WECC-NWPP-US	21,367	21,248	24,861	25,595	25,595	16.4%	19.8%	19.8%	14.0%
WECC-RMRG	9,516	9,275	15,047	15,760	15,760	58.1%	65.6%	65.6%	15.7%
WECC-SRSG	17,166	16,718	28,110	28,937	28,937	63.8%	68.6%	68.6%	13.9%
TOTAL-UNITED STATES	**642,914**	**609,741**	**914,565**	**918,644**	**937,981**	**42.3%**	**42.9%**	**45.9%**	**15.0%**
MRO-Manitoba Hydro	4,477	4,251	5,223	5,234	5,234	16.7%	16.9%	16.9%	12.0%
MRO-SaskPower	3,391	3,304	3,813	3,901	3,901	12.4%	15.0%	15.0%	13.0%
NPCC-Maritimes	5,552	5,165	6,700	6,700	6,700	20.7%	20.7%	20.7%	20.0%
NPCC-Ontario (IESO)	22,311	22,311	29,780	29,876	30,812	33.5%	33.9%	38.1%	21.3%
NPCC-Québec	37,153	35,473	41,079	41,079	41,133	10.6%	10.6%	10.7%	9.7%
WECC-NWPP-CA	43,475	43,149	51,484	51,493	51,493	18.4%	18.4%	18.4%	12.3%
TOTAL-CANADA	**116,359**	**113,653**	**138,078**	**138,282**	**139,273**	**18.7%**	**18.8%**	**19.7%**	**10.0%**
TOTAL-MÉXICO	**1,405**	**1,405**	**2,360**	**2,360**	**2,360**	**68.0%**	**68.0%**	**68.0%**	**10.7%**
TOTAL-NERC	**760,679**	**724,799**	**1,055,003**	**1,059,286**	**1,079,614**	**38.7%**	**39.3%**	**41.9%**	**15.0%**
EASTERN INTERCONNECTION	**540,734**	**510,005**	**764,098**	**766,022**	**786,295**	**41.3%**	**41.7%**	**45.4%**	**15.0%**
ERCOT INTERCONNECTION	**53,303**	**51,929**	**72,995**	**73,038**	**73,038**	**36.9%**	**37.0%**	**37.0%**	**13.75%**
QUÉBEC INTERCONNECTION	**37,153**	**35,473**	**41,079**	**41,079**	**41,133**	**10.6%**	**10.6%**	**10.7%**	**9.7%**
WESTERN INTERCONNECTION	**129,485**	**127,269**	**174,844**	**177,160**	**177,160**	**35.0%**	**36.8%**	**36.8%**	**15.0%**

Table 8: Demand, Resources, and Reserve Margins – December, 2011

Assessment Area / Country / NERC Interconnection	Demand		Capacity Resouces			Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Existing Certain and Net Firm Transactions (MW)	Anticipated (MW)	Prospective (MW)	Existing Certain and Net Firm Transactions (%)	Anticipated (%)	Prospective (%)	NERC Reference Margin Level (%)
ERCOT	48,841	47,467	70,483	70,526	70,526	44.3%	44.4%	44.4%	13.75%
FRCC	37,838	34,861	58,963	58,763	58,711	55.8%	55.3%	55.2%	15.0%
MISO	79,994	75,363	110,507	110,767	125,593	38.1%	38.5%	57.0%	15.0%
MRO-MAPP	4,700	4,370	6,751	6,753	6,753	43.6%	43.7%	43.7%	15.0%
NPCC-New England (ISO-NE)	21,153	19,289	31,084	31,084	31,084	46.9%	46.9%	46.9%	15.0%
NPCC-New York (NYISO)	24,533	22,651	36,024	37,006	39,531	46.8%	50.8%	61.1%	15.5%
PJM	122,418	110,890	188,345	189,311	183,565	53.9%	54.6%	49.9%	15.0%
SERC-E	39,278	38,059	54,147	53,946	53,946	37.9%	37.3%	37.3%	15.0%
SERC-N	43,055	41,753	57,427	57,427	57,441	33.4%	33.4%	33.4%	15.0%
SERC-SE	39,128	37,426	66,124	66,124	68,512	69.0%	69.0%	75.1%	15.0%
SERC-W	19,931	19,208	36,944	36,836	38,870	85.4%	84.8%	95.0%	15.0%
SPP	39,330	38,422	64,607	64,634	67,962	64.3%	64.3%	72.8%	13.6%
WECC-CAMX-US	36,560	35,598	54,970	55,003	55,003	50.4%	50.4%	50.4%	11.0%
WECC-NWPP-US	21,367	21,248	24,861	25,595	25,595	16.4%	19.8%	19.8%	14.0%
WECC-RMRG	9,516	9,275	15,047	15,760	15,760	58.1%	65.6%	65.6%	15.7%
WECC-SRSG	17,166	16,718	28,110	28,937	28,937	63.8%	68.6%	68.6%	13.9%
TOTAL-UNITED STATES	**604,807**	**572,597**	**904,395**	**908,474**	**927,791**	**49.5%**	**50.2%**	**53.4%**	**15.0%**
MRO-Manitoba Hydro	4,276	4,050	4,998	5,009	5,009	16.9%	17.1%	17.1%	12.0%
MRO-SaskPower	3,391	3,304	3,813	3,901	3,901	12.4%	15.0%	15.0%	13.0%
NPCC-Maritimes	5,324	4,949	6,693	6,693	6,693	25.7%	25.7%	25.7%	20.0%
NPCC-Ontario (IESO)	21,830	21,830	29,946	29,987	31,069	37.2%	37.4%	42.3%	21.3%
NPCC-Québec	33,970	32,290	41,426	41,176	41,231	21.9%	21.2%	21.4%	9.7%
WECC-NWPP-CA	43,475	43,149	51,484	51,493	51,493	18.4%	18.4%	18.4%	12.3%
TOTAL-CANADA	**112,266**	**109,572**	**138,360**	**138,259**	**139,396**	**23.2%**	**23.2%**	**24.2%**	**10.0%**
TOTAL-MÉXICO	**1,401**	**1,401**	**2,271**	**2,271**	**2,271**	**62.1%**	**62.1%**	**62.1%**	**10.7%**
TOTAL-NERC	**718,474**	**683,571**	**1,045,026**	**1,049,003**	**1,069,458**	**45.5%**	**46.0%**	**48.9%**	**15.0%**
EASTERN INTERCONNECTION	**506,178**	**476,425**	**756,373**	**758,242**	**778,642**	**49.4%**	**49.8%**	**53.8%**	**15.0%**
ERCOT INTERCONNECTION	**48,841**	**47,467**	**70,483**	**70,526**	**70,526**	**44.3%**	**44.4%**	**44.4%**	**13.75%**
QUÉBEC INTERCONNECTION	**33,970**	**32,290**	**41,426**	**41,176**	**41,231**	**21.9%**	**21.2%**	**21.4%**	**9.7%**
WESTERN INTERCONNECTION	**129,485**	**127,269**	**174,844**	**177,160**	**177,160**	**35.0%**	**36.8%**	**36.8%**	**15.0%**

Table 9: Demand, Resources, and Reserve Margins –January, 2012

Assessment Area / Country / NERC Interconnection	Demand		Capacity Resouces			Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Existing Certain and Net Firm Transactions (MW)	Anticipated (MW)	Prospective (MW)	Existing Certain and Net Firm Transactions (%)	Anticipated (%)	Prospective (%)	NERC Reference Margin Level (%)
ERCOT	53,303	51,929	72,995	73,038	73,038	36.9%	37.0%	37.0%	13.75%
FRCC	47,613	44,196	59,403	59,203	59,151	24.8%	24.3%	24.2%	15.0%
MISO	75,859	71,496	107,145	107,506	120,572	41.2%	41.7%	58.9%	15.0%
MRO-MAPP	5,036	4,672	6,725	6,727	6,727	33.5%	33.6%	33.6%	15.0%
NPCC-New England (ISO-NE)	22,255	20,391	32,299	32,299	32,308	45.1%	45.1%	45.2%	15.0%
NPCC-New York (NYISO)	24,533	22,651	36,194	37,176	39,711	47.5%	51.5%	61.9%	15.5%
PJM	130,711	118,885	193,492	194,458	188,712	48.0%	48.8%	44.4%	15.0%
SERC-E	42,459	41,067	54,310	54,109	54,109	27.9%	27.4%	27.4%	15.0%
SERC-N	47,123	45,808	57,401	57,401	57,415	21.8%	21.8%	21.8%	15.0%
SERC-SE	44,259	42,555	65,962	65,962	68,350	49.0%	49.0%	54.4%	15.0%
SERC-W	19,571	18,835	37,049	36,941	38,975	89.3%	88.8%	99.1%	15.0%
SPP	41,089	40,178	65,344	65,372	68,700	59.0%	59.1%	67.2%	13.6%
WECC-CAMX-US	34,533	33,246	53,005	53,261	53,261	53.5%	54.2%	54.2%	11.0%
WECC-NWPP-US	21,318	21,194	25,499	26,232	26,232	19.6%	23.1%	23.1%	14.0%
WECC-RMRG	9,015	8,770	16,283	16,009	16,009	80.6%	77.6%	77.6%	15.7%
WECC-SRSG	16,615	16,094	34,158	35,992	35,992	105.6%	116.6%	116.6%	13.9%
TOTAL-UNITED STATES	**635,292**	**601,967**	**917,265**	**921,687**	**939,264**	**44.4%**	**45.1%**	**47.8%**	**15.0%**
MRO-Manitoba Hydro	4,477	4,251	5,223	5,234	5,234	16.7%	16.9%	16.9%	12.0%
MRO-SaskPower	3,358	3,271	3,783	3,872	3,872	12.7%	15.3%	15.3%	13.0%
NPCC-Maritimes	5,552	5,165	6,700	6,700	6,700	20.7%	20.7%	20.7%	20.0%
NPCC-Ontario (IESO)	22,311	22,311	29,780	29,876	30,812	33.5%	33.9%	38.1%	21.3%
NPCC-Québec	37,153	35,473	41,079	41,079	41,133	10.6%	10.6%	10.7%	9.7%
WECC-NWPP-CA	41,307	40,954	51,876	51,942	51,942	25.6%	25.7%	25.7%	12.3%
TOTAL-CANADA	**114,159**	**111,426**	**138,441**	**138,702**	**139,693**	**21.3%**	**21.5%**	**22.4%**	**10.0%**
TOTAL-MÉXICO	**1,405**	**1,405**	**2,360**	**2,360**	**2,360**	**68.0%**	**68.0%**	**68.0%**	**10.7%**
TOTAL-NERC	**750,856**	**714,797**	**1,058,066**	**1,062,749**	**1,081,317**	**40.9%**	**41.5%**	**44.0%**	**15.0%**
EASTERN INTERCONNECTION	**536,207**	**505,732**	**760,811**	**762,837**	**781,350**	**41.9%**	**42.3%**	**45.7%**	**15.0%**
ERCOT INTERCONNECTION	**53,303**	**51,929**	**72,995**	**73,038**	**73,038**	**36.9%**	**37.0%**	**37.0%**	**13.75%**
QUÉBEC INTERCONNECTION	**37,153**	**35,473**	**41,079**	**41,079**	**41,133**	**10.6%**	**10.6%**	**10.7%**	**9.7%**
WESTERN INTERCONNECTION	**124,193**	**122,115**	**179,311**	**182,157**	**182,157**	**44.4%**	**46.7%**	**46.7%**	**15.0%**

Table 10: Demand, Resources, and Reserve Margins –February, 2012

Assessment Area / Country / NERC Interconnection	Demand		Capacity Resouces			Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Existing Certain and Net Firm Transactions (MW)	Anticipated (MW)	Prospective (MW)	Existing Certain and Net Firm Transactions (%)	Anticipated (%)	Prospective (%)	NERC Reference Margin Level (%)
ERCOT	49,846	48,472	71,186	71,229	71,229	42.8%	42.9%	42.9%	13.75%
FRCC	39,183	35,943	59,226	59,026	58,974	51.2%	50.6%	50.5%	15.0%
MISO	72,871	68,531	107,135	107,496	120,562	47.0%	47.5%	65.4%	15.0%
MRO-MAPP	4,753	4,436	6,640	6,642	6,642	39.7%	39.8%	39.8%	15.0%
NPCC-New England (ISO-NE)	21,765	19,901	32,343	32,343	32,352	48.6%	48.6%	48.6%	15.0%
NPCC-New York (NYISO)	24,533	22,651	36,069	37,051	39,579	47.0%	51.0%	61.3%	15.5%
PJM	125,895	114,069	193,492	194,458	188,712	53.7%	54.5%	49.9%	15.0%
SERC-E	40,307	38,908	54,235	54,034	54,034	34.6%	34.1%	34.1%	15.0%
SERC-N	45,038	43,711	57,122	57,122	57,139	26.8%	26.8%	26.9%	15.0%
SERC-SE	41,519	39,814	66,034	66,034	68,422	59.0%	59.0%	64.8%	15.0%
SERC-W	19,302	18,453	37,051	36,943	38,977	92.0%	91.4%	101.9%	15.0%
SPP	39,740	38,829	64,983	65,011	68,339	63.5%	63.6%	72.0%	13.6%
WECC-CAMX-US	33,590	32,307	50,045	50,434	50,434	49.0%	50.1%	50.1%	11.0%
WECC-NWPP-US	20,619	20,549	24,058	24,792	24,792	16.7%	20.2%	20.2%	14.0%
WECC-RMRG	8,828	8,583	16,295	16,947	16,947	84.6%	92.0%	92.0%	15.7%
WECC-SRSG	16,781	16,288	32,868	34,017	34,017	95.9%	102.7%	102.7%	13.9%
TOTAL-UNITED STATES	**604,570**	**571,444**	**908,783**	**913,580**	**931,153**	**50.3%**	**51.1%**	**54.0%**	**15.0%**
MRO-Manitoba Hydro	4,282	4,056	5,188	5,199	5,199	21.2%	21.4%	21.4%	12.0%
MRO-SaskPower	3,347	3,260	3,684	3,772	3,772	10.1%	12.7%	12.7%	13.0%
NPCC-Maritimes	5,482	5,114	6,649	6,649	6,649	21.3%	21.3%	21.3%	20.0%
NPCC-Ontario (IESO)	21,970	21,970	30,161	30,257	30,672	37.3%	37.7%	39.6%	21.3%
NPCC-Québec	35,443	33,763	40,900	40,900	40,956	15.4%	15.4%	15.6%	9.7%
WECC-NWPP-CA	39,304	39,091	47,965	48,653	48,653	22.0%	23.8%	23.8%	12.3%
TOTAL-CANADA	**109,828**	**107,254**	**134,547**	**135,430**	**135,900**	**22.5%**	**23.3%**	**23.7%**	**10.0%**
TOTAL-MÉXICO	**1,377**	**1,377**	**2,247**	**2,264**	**2,264**	**63.2%**	**64.4%**	**64.4%**	**10.7%**
TOTAL-NERC	**715,775**	**680,075**	**1,045,577**	**1,051,274**	**1,069,317**	**46.1%**	**46.9%**	**49.4%**	**15.0%**
EASTERN INTERCONNECTION	**509,987**	**479,645**	**760,013**	**762,038**	**780,026**	**49.0%**	**49.4%**	**53.0%**	**15.0%**
ERCOT INTERCONNECTION	**49,846**	**48,472**	**71,186**	**71,229**	**71,229**	**42.8%**	**42.9%**	**42.9%**	**13.75%**
QUÉBEC INTERCONNECTION	**35,443**	**33,763**	**40,900**	**40,900**	**40,956**	**15.4%**	**15.4%**	**15.6%**	**9.7%**
WESTERN INTERCONNECTION	**120,499**	**118,600**	**168,490**	**172,172**	**172,172**	**39.8%**	**42.9%**	**42.9%**	**15.0%**

ERCOT

Executive Summary

The forecasted 2011/2012 winter peak demand[64] is 53,562 MW and is expected to occur in January 2012. This forecast is 7 percent lower than the 2010/2011 winter actual peak demand of 57,315 MW, which was experienced during February 10, 2011 record-setting, sustained cold temperatures.

Out of the 88,896 MW of Existing capacity resources, *Existing-Certain* capacity ranges from a high of 71,920 MW to a low of 67,315 MW during the winter season due to scheduled maintenance of facilities. Since the previous winter assessment, 698 MW of *Existing–Certain* capacity, including 45 MW of biomass and 13 MW (effective) of wind, has been added.

ERCOT expects to add 30 MW of solar and 150 MW of wind (13 MW effective due to derating) during the assessment timeframe.[65] There are no other significant capacity additions (e.g. wind, biomass, coal, demand response) reported to ERCOT to occur during the winter assessment reporting period. Approximately 1,900 MWs of generation have announced plans to retire or suspend operations affecting the winter season, of which 1,160 MWs are directly attributable to Environmental Protection Agency Cross State Air Pollution Rule implementation.

ERCOT's planning reserve target requires a 13.75 percent or greater Reserve Margin. ERCOT's Reserve Margins for the winter season, based on *Existing–Certain* and Net Firm Transactions is 38 percent. When considering Anticipated Capacity Resources Reserve Margin, the Reserve Margin for the ERCOT region is relatively unchanged. Both metrics are at or beyond the required 13.75 percent target, throughout the assessment period.

ERCOT is currently undergoing severe drought conditions. Due to these conditions 24 MW of capacity is currently unavailable due to inadequate cooling water resources. ERCOT has surveyed generation owners to request information on the likelihood of drought-related unavailability during the assessment period and has interviewed those resource owners with potential drought-related problems. Results of the discussions are included in the Generation section of this report.

Several transmission improvements have been made throughout the ERCOT Region to meet reliability needs. Approximately 38 miles of new or upgraded 345 kV lines have been completed since the 2010/2011 winter and 418 miles of new or upgraded 345 kV lines are expected to be complete by the end of the 2011/2012 winter period. Approximately 111 miles of new or upgraded 138 kV transmission lines were completed since the 2010/2011 winter and an additional 329 miles of new or upgraded 138 kV lines are expected to be complete by the end of the 2011/2012 winter period.

[64] The forecasted peak demand is based on normal weather conditions expected to be experienced at the time of the system winter peak demand.

[65] The assessment horizon is December 1, 2011 through February 28, 2012.

There are no known transmission constraints that are expected to significantly impact reliability across the ERCOT Region during the winter period.

The recently finalized Cross State Air Pollution Rule (CSAPR) coupled with the expected continuation of the near-record Texas drought threatens the availability of sufficient generation for the ERCOT Region, particularly if extreme weather leads to above-normal demands. ERCOT recently completed an assessment of the CSAPR regulation.[66] This assessment found that generators' current compliance plans indicate that 1,200 to 1,400 MW of generation may be unavailable during this reporting period, reducing the reported Reserve Margins by about 2.5 percentage points. Subsequent to the release of ERCOT's CSAPR assessment, generation owners have notified ERCOT of intent to suspend commercial operations of 1,160 MWs as a result of CSAPR; this reduction is incorporated into the numeric values in this winter assessment. As interpretations and updates to CSAPR are released, definitive retirements or significant de-rates may change. Nevertheless, ERCOT is actively studying options to ensure adequacy of resources for worst case scenarios of short-term or seasonal unavailability of resources.

Should both the CSAPR and the drought scenarios occur, roughly 4,400 MW of capacity (a 3,200 MW reduction from the reported values) may be unavailable during this assessment period. Despite this potential unavailability, with a normally expected generation outage rate and a normal weather forecast, ERCOT should maintain a Reserve Margin in excess of the 13.75 percent Reserve Margin for the winter season.

The overall impact of a CSAPR capacity reduction of 1,400 MW (an additional impact of ~200 MW over the reported values) and extreme drought-based capacity reduction of over 9,000 MW due to water right curtailment would result in a significant reduction in the Reserve Margin. At this level of reserves the sensitivity of impacts of unusual operating conditions, such as an increased generation outage rate or extreme load due to extreme weather conditions would likely lead to capacity insufficiency.

Introduction

The ERCOT Region is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority (BA) and Reliability Coordinator (RC) area. This report assesses the adequacy of resources necessary to serve ERCOT load during winter of 2011/2012. Generation capacity data is reported to ERCOT by generation owners. ERCOT develops demand forecasts based on economic, weather, and historical load data. This document is an all-inclusive winter assessment for the ERCOT region. This document does not consider resource adequacy of non-ERCOT systems located within the state of Texas.

Demand

The 2010/2011 winter actual peak demand was 57,315 MW and was experienced during extreme cold temperature across the entire Region on February 10, 2011.[67] The 2011/2012 winter peak Total Internal

[66] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

[67] ERCOT develops energy and demand forecasts using econometric regression models to predict monthly energy consumption for each of eight weather zones defined across the ERCOT Region and neural network-based models to allocate the energy use for each weather zone.

Demand forecast of 53,303 MW is approximately 11 percent higher than the 2010/2011 winter peak demand forecast of 47,842 MW (Table 11). This difference is largely due to use of a colder winter weather temperature profile in the forecast model considering the extreme cold weather experienced in February 2011 in the assessment of the likelihood of expected temperatures. Additionally, there was improvement in non-farm employment, as reported by Moody's, for ERCOT counties which increased the demand forecast. Actual coincident hourly demands are also used in the development of forecasts. The forecasted peak demands are produced by the ERCOT ISO for the entire ERCOT Region, which is a single BA Area, based on the region-wide actual demands. The peak condition that determines these load forecasts is an average weather profile (50/50). The data used in the forecast is differentiated by weather zones.

Table 11: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**53,303**	**January-2012**
2010/2011 Forecast	47,824	January-2011
2010/2011 Actual	57,315	February-2011
All-Time Peak	57,315	February-2011

While the forecasted peak demands produced using the average weather profile are used for resource assessments, alternative weather scenarios are used to develop extreme weather load forecasts to assess the impact of weather variability on the peak demand for ERCOT. One scenario is the one-in-ten-year occurrence of a weather event. This scenario is calculated using the 90th percentile of the temperatures in the database spanning the last fifteen years. These extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The extreme temperature assumptions produce a demand forecast that is approximately 7 percent higher than the forecast based on the average weather profile (50/50) for the winter season, or 57,539 MW (slightly higher than last year's actual peak). Together, the forecasts from these temperature scenarios are usually referred to as 90/10 scenario forecasts. ERCOT incorporates extreme weather conditions to determine whether variability impacts on load forecasts. Given the probability of that occurrence, the associated impact to resource adequacy and reduction in Reserve Margins are reviewed.

There are two categories of demand response resources that can be dispatched by the ERCOT ISO in all hours, and therefore are capable of reducing winter peak demand. Load Resources (LRs) providing Responsive Reserve Service provide an average of approximately 1,063 MW of dispatchable, contractually-committed Supply-Side Load as a Capacity Resource during summer peak hours based on the most recently available data (Table 12).[68] ERCOT's Emergency Interruptible Load Service (EILS), is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "firm" load, and also represents Supply-Side Contractually Interruptible Demand.[69] Based on average EILS commitments for the winter of 2010/2011, approximately 417 MW of EILS Load can be counted upon

across each hour of the month. The growth in consumption over time, based on historic patterns, is driven by non-farm employment. The use of non-farm employment and actual historical loads incorporate the regional impact of the economic recession.

[68] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.

[69] http://www.ercot.com/services/programs/load/eils/.

during the winter peak. Together these two programs would reduce winter peak demand by a little over three (3) percent if activated at that time. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[70]

Table 12: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**259**
Non-Controllable Demand-Side Management	**-**
Direct Control Load Management	-
Contractually Interruptible (Curtailable)	311
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	1,063
Total Dispatchanle, Controllable Demand Response	**1,374**
Total Demand-Side Management	**1,633**

Texas Senate Bill 1125 was recently passed by the Texas legislature and signed by the Governor of Texas and became effective on 9/1/2011.[71] This Bill sets an Energy Efficiency requirement of 0.4 percent of residential and commercial peak demand. It was assumed that half of the Energy Efficiency target from Senate Bill 1125 was already reflected in the load forecast due to review of historical program implementation. Therefore, ERCOT forecasts values of Energy Efficiency as 0.2 percent of the residential and commercial annual peak demand.

In general, utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities.[72] In the latest assessment, utility programs implemented after electric utility industry restructuring in Texas, had produced 1,666 MW of peak demand reduction and 4,110 GWh of electricity savings for the years 1999 through 2010.[73] This demand reduction is accounted for within the load forecast and only the expected incremental portion for the coming year is included as a demand adjustment.

The 2011/2012 Forecast was based on the base case economic forecast from Moody's. For approximately the last year, actual non-farm employment has been tracking the Moody's base case economic forecast. It appears that Texas' non-farm employment is growing at a significantly higher rate than the U.S. as a whole.

Generation

ERCOT has approximately 71,920 MW of *Existing-Certain* generation, 10,657 MW of Existing–Other generation, and 43 MW of Future Planned generation capacity expected to be in service during the 2011/2012 winter period peak.

[70] http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc.

[71] http://www.capitol.state.tx.us/tlodocs/82R/billtext/html/SB01125F.htm.

[72] http://www.texasefficiency.com/report.html.

[73] http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf.

The amount of *Existing-Other* generation includes 6,095 MW of capacity associated with units undergoing maintenance or repair during the first week of the reporting period (which is decreased to 1,490 MW at the time of the expected winter peak load in January) and 4,945 MW of units not readily available due to their mothball status (listed as *Existing-Inoperable*) throughout the planning period, which includes 1,160 MW that was recently announced to be mothballed due to CSAPR.[74] This first week reflects the largest capacity outages that are planned for the period, and is not expected to adversely affect the ability to meet demand.

Out of the 9,452 MW of installed wind capacity, only 8.7 percent, or 822 MW, is used as *Existing-Certain* generation. The remaining 8,630 MW of the existing wind capacity is included in the *Existing-Other* generation amount. Similarly, the planned new wind generation expected to be online by the winter period totals 150 MW, however only 13 MW (8.7 percent) are considered on-peak (Table 13).[75] Additional solar generation of 30 MW is expected to be added prior to the winter period. In addition, 61 MW of biomass is included in the Existing–Certain generation amount.

Table 13: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	820
	Derated	8,600
	Wind - Total Nameplate Capacity	**9,420**
Solar	Expected	15
	Derated	-
	Solar - Total Nameplate Capacity	**15**
Hydro	Expected	-
	Derated	540
	Hydro - Total Nameplate Capacity	**540**
Biomass	Expected	61
	Derated	-
	Biomass - Total Nameplate Capacity	**61**

While reservoir levels are currently below average, less than 1 percent of the ERCOT generation capacity is hydro. These facilities are typically operated as run-of-river or planned release due to downstream needs, and are not operated specifically to produce electricity.

ERCOT is currently engaged in a study of natural gas fuel supply vulnerability that is expected to be complete before the end of the year. The ERCOT Region is not generally reliant on single gas pipelines or import paths such that the long-term outage of one of these types of lines or paths would lead to the loss of significant amounts of generating capacity.

[74] See Section 2 of the ERCOT Protocols at http://www.ercot.com/mktrules/nprotocols/lib.

[75] The 8.7 percent of wind installed capacity is based on a 2007 study of the effective load-carrying capability (ELCC) of wind generation. The 2010 LOLEv Study updated the ELCC calculation, but ERCOT did not adopt the revised ELCC for use in Reserve Margin calculations. The 2010 LOLEv Study is available at: http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip.

ERCOT is currently undergoing severe drought conditions. Due to these conditions, 24 MW of capacity is currently unavailable due to inadequate cooling water resources. ERCOT has surveyed generation owners to request information on the likelihood of drought-related unavailability during the assessment period and has interviewed those resource owners with potential drought-related problems. If the ERCOT region receives roughly half of normal winter rainfall, generation owners anticipate that over 400 MW of total capacity are expected to become unavailable across the winter season. In the extreme case of no significant rainfall across the entire Region through the winter could result in over 2,900 MW of generation becoming unavailable by February of 2012. In addition, there is over 9,000 MW that is at risk of curtailment if their water rights are recalled to allow the available water to be used for other purposes. While the latter scenario is unlikely, entities in the Region are investigating and implementing mitigating measures. These measures, some of which have already occurred for some locations, include:

- Building of pipelines to remote water sources
- Procurement of additional water rights
- Addition of pumping capability

At the request of the Public Utility Commission of Texas, ERCOT has reviewed the likely impact of various EPA rule changes on generating capacity in the region. While several of these regulations may have a cumulative impact on the future availability of generation in the Region, only the Cross State Air Pollution Rule is likely to have an impact during the assessment period. Generation owners must submit a Notice of Suspension of Operations to ERCOT 90 days in advance of any retirement, or suspension of operations for more than six months. ERCOT has received two notices of this type totaling 1,160 MWs directly attributable to EPA regulation implementations. ERCOT recently completed an assessment of the CSAPR regulation which anticipated the suspension of operations of the 1,160 MW as well as approximately 200 MW of additional derating due to CSAPR compliance impacts of units that continue to operate.[76]

Capacity Transactions

The ERCOT Region is a separate interconnection with only asynchronous ties to SPP and Mexico's Comisión Federal de Electricidad (CFE) and does not share reserves with other regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability. The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by transferring block loads to the eastern interconnection.

For the winter 2011/2012 season, ERCOT has 458 MW of imports from SPP and 140 MW from CFE. Of the imports from SPP, 48 MW is tied to a long term contract for a purchase of firm power from specific generation. The remaining imports of 410 MW from SPP and 140 MW from CFE represent one-half of the asynchronous tie transfer capability to reflect emergency support arrangements between systems. Several SPP members own 317 MW of a power plant located in the ERCOT Region which is switchable between ERCOT and SPP (Table 14). The result is shown as a firm export of that amount from ERCOT to

[76] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

SPP in capacity calculations. There are no non-Firm contracts signed or pending. There are also no known contracts under negotiation or under study.

Table 14: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	598
	Expected	-
	Non-Firm	-
	Total	**598**
Exports	Firm	317
	Expected	-
	Non-Firm	-
	Total	**317**
Net Transactions		**281**

Transmission

Several significant transmission improvements have been made throughout the ERCOT Region to meet reliability needs (Table 15).[77] The largest planned improvement, in terms of circuit miles, located east of the North Central Texas Area, is a new double circuit 345 kV line from the TNP One plant to a new Bell County East switching station near Temple. The project will reduce congestion from the newly built and planned coal plants in the area.

Table 15: Recent Transmission Additions/Upgrades[78]

Voltage	Additions (Circuit Miles)	Upgrades (Circuit Miles)
345 kV	37	418
138 kV	111	329

In the North Central Texas area, a second 345 kV circuit has been added to existing structures to increase import from the wind generation located in the West Texas areas into the Dallas/Fort Worth load center. This 37 circuit mile 345 kV circuit from Krum West Switch to NW Carrolton, endorsed as part of the larger Commercial Renewable Energy Zones (CREZ) initiative, will mitigate congestion during periods of high wind generation.[79] Other CREZ related work scheduled to be in service before the end of the 2011/2012 winter season includes Scurry County to Tonkawa Switching Station (30 circuit miles of new, double circuited 345 kV line), Tonkawa to Sweetwater East Line (63 circuit miles of new double circuited 345 kV line), and Dermott Switch To Scurry County (65 circuit miles of new double circuited 345 kV line.) Auto-transformers and reactors will be installed at Scurry County South, Dermott, and Central Bluff Switching Stations, for a total of 3600 MVA and 450 MVAr respectively. Collectively, these transmission additions will ease existing constraints associated with the export of wind energy from West Texas, delivered to the metropolitan load centers of ERCOT.

[77] Additional details on transmission projects can be found in the "Transmission Project Implementation and Tracking database" located on the following website: http://planning.ercot.com/reports/tpit/ (registration required).

[78] Since the 2010/2011 winter season.

[79] http://www.texascrezprojects.com/.

An additional 300 MVAr SVC was added to Renner substation in the Dallas area since the last winter assessment. Seven hundred fifty (750) MVAr of shunt reactance is anticipated to be in service by the end of this assessment period at various 345 kV stations that are part of the Competitive Renewable Energy Zone construction, primarily in West Texas. Approximately 700 MVAr of shunt capacitance has been added to the ERCOT system since the previous winter reporting period.

ERCOT will employ congestion management techniques and develop mitigation plans if necessary, to maintain reliability. Hence there are no anticipated reliability concerns with not meeting target in-service dates for new transmission additions at this time.

There are no known transmission constraints that are expected to significantly impact reliability across the ERCOT region. Some transmission outages may be scheduled during the winter season. ERCOT performs outage coordination to maintain reliability for any planned transmission outages. As transmission constraints are identified, remedial action plans or mitigation plans are developed to provide for preemptive or planned responses to maintain reliability. No transmission constraints are expected to significantly impact reliability during the winter season. Interregional transfer capabilities are not generally relied upon to resolve transmission reliability planning although emergency support arrangements are in place which provide for support over the asynchronous ties or through block load transfers.

Operational Issues

For the 2011/2012 winter season, ERCOT is performing several special operating studies for the ERCOT Region. In response to a severe drought experienced across the ERCOT Region, ERCOT is updating the impact of the drought on cooling water levels and the availability of thermal generation on a weekly basis. The potential impact of the recently passed Cross-State Air Pollution Rule is also under additional study.

ERCOT will use typical operational procedures related to variable resources during the winter season. ERCOT has implemented a wind power forecasting system to allow ERCOT ISO System Operators to identify and take appropriate action when wind resource schedules may not track expected changes in wind production. ERCOT has also implemented a wind ramp forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods.[80] In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis. ERCOT does not anticipate any reliability concerns resulting from minimum demand and over generation.

ERCOT limits the participation of Supply-Side Load as a Capacity Resource, or Load Resources, to providing 50 percent of the Responsive Reserve Service (currently a 1,150 MW limit), which is deployed in response to large frequency excursions (below 59.7 Hz) or during system emergencies, such as Energy

[80] Wind output by different regions within ERCOT is provided in a real-time display to improve System Operator situational awareness.

Emergency Alerts (EEA).[81] ERCOT procures Demand Response (DR) products around the clock to address system conditions at all times – not just during peak demand periods. ERCOT's monitoring and testing programs provide confidence that the DR resources will perform when called. The status of Load Resources providing Ancillary Services is monitored in real time via 2-second telemetry. Supply-Side Contractually Interruptible Demand, known as Emergency Interruptible Load Service (EILS) load, is monitored using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability requirements. Both DR products are subject to annual unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension.

As previously mentioned, at the request of the Public Utilities Commission of Texas, ERCOT has reviewed the likely impact of various EPA rule changes on generating capacity in the Region. While the cumulative impact of the new regulations on the future availability of generation in the ERCOT Region may be significant, only the Cross State Air Pollution Rule (CSAPR) is likely to have an impact during the assessment period. ERCOT recently completed an assessment of the proposed inclusion of Texas in the Cross State Air Pollution Rule (CSAPR replaces CATR).[82] The assessment found that, if the rule is implemented as currently scheduled on January 1, 2012, then generators' current compliance plans indicate that 1,200 to 1,400 MW of generation would be unavailable year round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months. The unavailability of this generation would increase capacity insufficiency and the need for emergency actions including rotating outages, not only during the peak months but also during the off-peak months until retrofits or alternative resources are implemented. ERCOT has recently received a Notice of Suspension of Operations directly attributable to new EPA regulations (totaling 1160 MW) and therefore this winter seasonal assessment is based on the anticipated unavailability of those units. While other market participants have expressed compliance strategies, no more official notices have been made to ERCOT to suspend operations related to CSAPR.

There are no other anticipated unusual operating conditions, other than the CSAPR and drought issues, that could significantly impact reliability for the upcoming winter. The sensitivity of impacts on the Reserve Margin due to unusual operating conditions, such as an increased generation outage rate, is magnified if extreme weather conditions coincide with the possible CSAPR and drought impacts.

Reliability Assessment

This assessment is generally based upon data collected from market participants pursuant to the ERCOT Protocols and forecasts/studies produced by ERCOT.[83]

The projected Reserve Margin (Existing) for winter 2011/2012 is 38 percent, significantly lower than the 2010/2011 margin of 57 percent. This change is primarily caused by a significant increase in the winter forecasted peak as a result of the temperature model improvements. This projected Reserve Margin is

[81] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.

[82] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

[83] http://www.ercot.com/mktrules/nprotocols/current.

well over the ERCOT Region minimum annual Reserve Margin of 13.75 percent. The ERCOT minimum Reserve Margin target of 13.75 percent is based on Loss-of-Load Events (LOLE) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in 2010.[84]

Should both the CSAPR and the drought scenarios occur, roughly 4,400 MW of capacity (a 3,200 MW reduction from the reported values) may be unavailable during this assessment period. Despite this potential unavailability, with a normally expected generation outage rate and a normal weather forecast, ERCOT should remain above 13.75 percent, the Planning Reserve Margin Reference Level for the winter season.

The overall impact of a CSAPR capacity reduction of 1,400 MW (an additional impact of approximately 200 MW over the reported values) and extreme drought-based capacity reduction of over 9,000 MW due to water right curtailment would result in a significant reduction in reserves to about 20 percent.

At this level of reserves the sensitivity of impacts of unusual operating conditions, such as an increased generation outage rate or extreme load due to extreme weather conditions would likely lead to capacity insufficiency.

In the planning horizon, ERCOT performs a security-constrained unit commitment and economic dispatch analysis for the upcoming year.[85] In the operations horizon, resource adequacy is maintained by ERCOT ISO through market-based procurement processes.[86] Maintaining operations within transmission operating limits are primarily managed through market-based generation redispatch directed by ERCOT ISO as the Balancing Authority and Reliability Coordinator. Firm load shed actions, if necessary to maintain operating limits, are/will be utilized.

ERCOT is a member of the Texas Energy Reliability Council (TERC).[87] TERC is comprised of representatives from Texas natural gas intrastate pipelines, producers and distributors and electric generation companies. TERC is facilitated by the Railroad Commission of Texas, the state regulator of natural gas. TERC helps coordinate and, if necessary, allocates supplies of natural gas during periods of high demand and potential shortages. It meets at least annually to discuss issues regarding natural gas supply to electric generating plants and other customers.

ERCOT receives communication regarding fuel supply issues from all Generator Owners/Operators in the Region on a day-ahead and intra-day basis via resource plans and verbal notifications. The Generator Owner/Operators advise ERCOT on any localized fuel supply issues communicated to them by their suppliers that might affect the availability of their generation resources. Some generators also have alternate fuel capability (oil) that they can switch to if gas is curtailed. ERCOT is in the process of hiring a

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84 http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip.

85 This analysis is performed on an hourly basis for a variety of conditions to ensure deliverability of sufficient resources to meet a load level that is approximately 10 percent higher than the expected summer coincident system peak demand plus operating reserves.

86 See Sections 6 and 7 of the ERCOT Protocols found at http://www.ercot.com/mktrules/protocols/current.

87 http://www.rrc.state.tx.us/about/divisions/reliabilitycouncil/index.php.

consultant to perform a natural gas curtailment risk study of the ERCOT system. The intent of the study is to quantify the risks which include both physical, commercial, and if applicable, regulatory barriers to natural gas delivery to electric generating stations. This consultant will also investigate past events including the February 2011 event. The final natural gas curtailment risk study report is expected to be available in January 2012 and will be presented to the Texas Public Utility Commission.

By maintaining an appropriate voltage profile at generating units and coordinating voltage-control equipment, it is possible to maintain transmission grid voltages at all points in ERCOT within acceptable operating voltage limits.[88,89] Transient and voltage stability studies performed on the 2011/12 winter network models shows no reliability concerns.

Following the February 2, 2011 winter event in which a significant amount of generation in the ERCOT Region became unavailable due to low temperatures and wind chill factors, ERCOT held a Severe Weather Readiness Workshop.[90] Senior executives from most of the generating entities in the Region discussed "lessons learned" regarding the February 2nd event, as well as the February 10, 2011 system peak that occurred during similar weather conditions with little loss of generation. Based on the February 10th experience, as well as commitments made during the workshop, it is not expected that the significant loss of generation would recur this upcoming winter season even if similar weather is experienced.[91]

Assessment Area Description

The ERCOT Region[92] is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority. ERCOT is a summer-peaking region responsible for about 85 percent of the electric load in Texas with an all-time peak demand of 68,294 MW set on August 3, 2011. The Texas Reliability Entity[93] (Texas RE) performs the regional entity functions described in the Energy Policy Act of 2005[94] for the ERCOT Region.

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88 Voltage profiles can be found at: http://www.ercot.com/gridinfo/generation/voltprof.

89 Steady state models for winter conditions are used to run a voltage profile study for the winter period.

90 http://www.ercot.com/calendar/2011/06/20110608-OTHER .

91 http://www.ercot.com/content/meetings/other/keydocs/2011/20110608OTHER/ERCOT_Generation_Weatherization_Workshop_06_08_11_FINAL.pdf.

92 ERCOT Region Website: http://www.ercot.com.

93 Texas Reliability Entity Website: http://www.texasre.org.

94 FERC Energy Policy Act 2005: http://www.ferc.gov/legal/fed-sta/ene-pol-act.asp.

FRCC

Executive Summary

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating reserves of 60,241 MW[95] with transmission system deliverability throughout the 2011/2012 forecasted non-coincident winter peak demand of 47,613 MW. Based on the expected load and generation capacity, the calculated Reserve Margin for the winter of 2011/2012 is 24.3 percent.

The transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand and planned firm transmission service. Although operational issues can develop due to unplanned outages of transmission facilities or generating units within the FRCC Region, it is anticipated that existing operational procedures, pre-planning, and strategies will adequately manage and mitigate these potential impacts to the bulk transmission system.

Introduction

The FRCC Region is typically summer peaking and divided into 10 Balancing Authorities. FRCC has registered 72 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida.

The purpose of this report is to assess the reliability of the FRCC Region for the upcoming winter season (2011-2012). The FRCC assessment process is performed in accordance with the Florida Public Service Commission (FPSC) requirement that all Florida utilities file an annual Ten Year Site Plan that details how each utility will manage growth for the next decade. The data from the individual entity plans is aggregated and used in the assessment process to evaluate resource and transmission adequacy.

Demand

The Florida Reliability Coordinating Council is forecasted to reach its 2011/12 winter peak demand of 47,613 MW in January 2012, which represents a projected demand increase of 3.6 percent over the actual 2010/11 winter demand of 45,954 MW (Table 16). This projection is consistent with historical weather-normalized FRCC demand growth and is 3 percent higher than last year's winter (2010/2011) forecast of 46,235 MW. The increase in the 2011/12 winter peak demand forecast is mostly attributed to an increase in employment over last year coupled with a projected increase in the state's population and the calibration of the peak demand models to align historical and forecasted demands.[96]

[95] Includes 3,417 MW of Demand Response.

[96] https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202011%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20RE%20PC%20Approved%20070611.pdf.

Table 16: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**47,613**	**January-2012**
2010/2011 Forecast	46,235	January-2011
2010/2011 Actual	46,220	December-2010
All-Time Peak	52,368	January-2010

Each individual Load Serving Entity (LSE) forecast takes into account historical temperatures to determine the normal temperature at the time of peak demand. Each individual LSE within the FRCC Region develops a forecast that accounts for their actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the regional level. The entities within the FRCC Region plan their systems to meet the Reserve Margin criteria under both summer and winter peak demand conditions.

There are a variety of energy efficiency programs implemented by entities throughout the FRCC Region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high efficiency lighting rebates.[97] The 2011/12 net internal FRCC peak demand forecast includes the effects of new energy efficiency programs as well as 3,417 MW (7.1 percent of Total Internal Demand) of potential demand reductions from the use of direct control load management and interruptible load management programs composed of residential, commercial and industrial demand. Entities within FRCC use different methods to test and verify Direct Load Management programs such as actual load response to periodic testing, use of a time and temperature matrix and the number of customers participating (Table 17). There currently is no critical peak pricing with control incorporated into the FRCC projection. Each LSE within the FRCC treats every Demand Side Management load control program as "demand reduction" and not as a capacity resource.

Table 17: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**-**
Non-Controllable Demand-Side Management	
Direct Control Load Management	2,783
Contractually Interruptible (Curtailable)	634
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**3,417**
Total Demand-Side Management	**3,417**

[97] Additional details can be found in the 10-Year Site Plan filing for each entity at the following link: https://www.frcc.com/Planning/default.aspx?RootFolder=%2fPlanning%2fShared%20Documents%2fFRCC%20Presentations%20and%20Utility%2010%2dYear%20Site%20Plans%2f2011&FolderCTID=&View=%7bFBDE89E4%2dE66F%2d40EE%2d999D%2dCFF06CF2A726%7d.

FRCC periodically assesses the peak demand uncertainty and variability by developing regional bandwidths. The purpose of developing bandwidths on peak demand loads is to quantify uncertainties of demand at the regional level. This would include weather and non-weather load variability such as demographics, economics and price of fuel and electricity. The influences of extreme winter conditions are not considered explicitly, but such conditions are implicitly examined within the bandwidth analyses to account for such extreme temperature deviations from weather-normalized forecasts.

Generation

FRCC Existing resources considered for this winter assessment are categorized as *Existing-Certain*, Existing Inoperable, and *Existing-Other* are shown in the Table FRCC-1 below.

Existing-Inoperable resources (2,876 MW) for this winter are composed of approximately 565 MW removed for plant modernization, 872 MW removed for unit repairs, while the balance of the capacity includes mostly older less efficient generating capacity being placed into operational standby until forecasted loads resume to pre 2007 recessional levels (Table 18).

Table 18: Table 19: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	-
	Derated	-
	Wind - Total Nameplate Capacity	**-**
Solar	Expected	1
	Derated	46
	Solar - Total Nameplate Capacity	**47**
Hydro	Expected	44
	Derated	11
	Hydro - Total Nameplate Capacity	**55**
Biomass	Expected	367
	Derated	14
	Biomass - Total Nameplate Capacity	**381**

The Region is expected to add less than 20 MW of *Future-Planned* generation for the winter season. The FRCC Region has a negligible amount of Variable Generation. The FRCC Region does not rely on hydro generation, therefore hydro conditions and reservoir levels will not impact the ability to meet the peak demand and the daily energy demand.

For the 2011/12 winter period, load serving concerns are not anticipated due to fuel reliability vulnerabilities including the availability of supplies. For extreme weather conditions such as widespread extreme cold temperatures resulting in natural gas peak usage or impacts to natural gas pipeline infrastructure, the availability of alternate short-term fuel capability continues to be adequate for the Region. There is no additional fuel availability or supply issues identified at this time and existing mitigation strategies continue to be refined. Based on recent studies, current fuel diversity, alternate fuel capability and fuel reliability analysis, the FRCC does not anticipate any fuel transportation issues affecting resource capability during peak periods and/or extreme weather conditions this winter.

The FRCC Region has not identified any unit retirements or planned unit outages that could have a significant impact on reliability during the upcoming winter season.

Capacity Transactions on Peak

Currently, there are 2,215 MW of generation under Firm contract that are available to be imported into the Region on a firm basis from the Southeastern Subregion of SERC (Table 20). No portion of these contracts is from Liquidated Damages or "make whole" contracts. These purchases have firm transmission service to ensure deliverability into the FRCC Region; no Imports with partial path reservations are included for Reserve Margin calculations. No Non-Firm or Expected transactions are included in the assessment. The FRCC Region Reserve Margin calculation does not rely on external resources for emergency imports and reserve sharing.

Table 20: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	2,215
	Expected	-
	Non-Firm	-
	Total	**2,215**
Exports	Firm	-
	Expected	-
	Non-Firm	-
	Total	**-**
Net Transactions		**2,215**

However, there are emergency power contracts (as available) in place between SERC and FRCC entities.

Presently, the FRCC Region has no Firm winter contract exports into the Southeastern Subregion of SERC. The FRCC does not consider Non-Firm or Expected sales to other regions as capacity resource reductions.

Transmission

For the upcoming winter 2011/2012 there are no concerns in meeting targeted in-service dates for any new transmission line additions or upgrades. No significant transformer or substation equipment (*i.e.,* SVC, FACTS controllers, HVdc, etc.) additions are expected for the upcoming winter 2011/2012. Presently there are seven 500kV transmission lines expected to be scheduled out of service individually at different times and coordinated with expected weather conditions.

Transmission constraints in the Central Florida area may require remedial actions depending on system conditions creating increased west-to-east flow levels across the Central Florida metropolitan load areas. Permanent solutions such as the addition of new transmission lines and the rebuild of existing 230kV transmission lines are planned and implementation of these solutions are underway and expected to be complete by 2013. In the interim, remedial operating strategies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability.

The interregional total transfer capability between the FRCC and the Southeastern Subregion of SERC for the winter is determined by the coordinated studies of Operations Planners. Joint studies of the Florida/Southeastern transmission interface have indicated a potential winter seasonal import capability of 3,800 MW into the region, and a potential export capability of 1,900 MW. These transfer capabilities take into account constraining facilities within the FRCC as well as within the Southeastern Subregion of SERC.

Operational Issues

FRCC expects the bulk transmission system to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the winter peak demand. The results of the 2011/12 Winter Transmission Assessment, which evaluated the steady-state winter peak load conditions under different operating scenarios, indicate that any concerns with thermal overloads or voltage conditions can be managed successfully by operator intervention. Such interventions may include generation redispatch, system sectionalizing, reactive device control, and transformer tap adjustments. The operating scenarios analyzed included the unavailability of major generating units within the FRCC. Therefore, various dispatch scenarios were evaluated to ensure generating resources within the FRCC are deliverable by meeting NERC Reliability Standards under these operating scenarios.

The FRCC Region has in place a cold-weather preparation check list identifying items to review prior to and during cold weather periods. The check list will be reviewed during conference calls to help entities proactively address potential cold weather issues such as reviewing operation on liquid fuel, ensuring that appropriate permitting is in place, addressing potential de-mineralized water constraints and any other cold weather induced environmental constraints, which may impact dispatch, examining the potential for initiating Energy Emergency Alerts (and associated procedures), reviewing the Available Transfer Capability and associated model ratings, etc.

The amount of variable generation within the FRCC Region is negligible having no potential to cause over generation. Therefore, no operational changes are needed due to the integration of small amounts of variable generation. Demand Side Management load control programs within the FRCC are treated as “demand reduction” and not as a capacity resource. The expected levels of demand reduction programs throughout the FRCC Region are not expected to cause any reliability concerns. There are no foreseen environmental restrictions identified at this time that could potentially impact reliability in the FRCC Region throughout the assessment period. The Cross State Air Pollution Rule (CSAPR) initiative of the U.S. Environmental Protection Agency is not expected to be a concern within Florida during the winter months.

The FRCC has a Reliability Coordinator (RC) agent that monitors real-time system conditions and evaluates near-term operating conditions of the bulk electric grid. The Reliability Coordinator uses a region-wide state estimator and contingency analysis program to evaluate current system conditions.[98] These tools enable the FRCC Reliability Coordinator to study and implement operational procedures

[98] These programs are provided with input data from operating entities on a periodic basis.

such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments to successfully mitigate line loading and voltage concerns that may occur in real time.

Reliability Assessment

The FRCC assessment process is performed in accordance to the Florida Public Service Commission (FPSC) requirement that all Florida utilities file an annual Ten Year Site Plan that details how each utility will manage growth for the next decade. The data from the individual plans is aggregated into the FRCC Load and Resource Plan[99] that is produced each year and filed with the Florida Public Service Commission.

Individual entities within the FRCC Region are required by the State of Florida to maintain a 15 percent Reserve Margin (20 percent for individual Investor Owned Utilities). Based on the expected load and generation capacity, the calculated Reserve Margin for the winter of 2011/12 is 24.3 percent when Load Management and Interruptible loads are treated as a resource under Controllable Capacity Demand Response (CCDR). This year's calculated Reserve Margin is lower than last year's (2010/2011) Reserve Margin calculation of 34.3 percent. For Regional purposes of Reserve Margin calculations, the FRCC uses Load Management and Interruptible loads as a demand reduction under CCDR, thus providing an equivalent Reserve Margin of 26.2 percent for the same megawatts of reserve.

The expected Reserve Margin for this winter includes a total of 2,215 MW import from the Southeastern Subregion of SERC to the FRCC. The total import into the FRCC Region consists of two components, including 872 MW of generation residing in the Southeastern Subregion of SERC owned by FRCC entities, and the remaining 1,343 MW are firm purchases. These imports account for 4.7 percent of the total internal demand, and have firm transmission service to ensure deliverability into the FRCC region.

The FRCC has historically used the Loss-of-Load-Probability (LOLP) analysis to confirm the adequacy of reserve levels for peninsular Florida. The LOLP analysis incorporates system generating unit information (e.g., Availability Factors and Forced Outage Rates) to determine the probability that existing and planned resource additions will not be sufficient to serve forecasted loads. The objective of this study is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1 day in a given year is not exceeded. The results of the most recent LOLP analysis conducted in 2009 indicated that for the "most likely" and extreme scenarios (*e.g.,* extreme seasonal demands; no availability of firm and non-firm imports into the region; and the non-availability of load control programs), the FRCC electric system maintains a LOLP below the 0.1 day per year criterion.

Under firm transactions, reactive power-limited areas can be identified during transmission assessments performed by the FRCC. These reactive power-limited areas are typically localized pockets that do not affect the BES. The FRCC 2011/12 Winter Transmission Assessment did not identify any static reactive power-limited areas that would impact the bulk electric system during the upcoming winter season.

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[99] https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202011%20Load%20and%20Resource%20Plan.pdf.

The FRCC Operating Committee has developed procedures, including 'FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers', to enhance the existing coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators and in response to FERC Order 698.[100]

For capacity constraints due to inadequate fuel supply, the FRCC State Capacity Emergency Coordinator (SCEC) along with the Reliability Coordinator (RC) have been provided with an enhanced ability to assess Regional fuel supply status by initiating Fuel Data Status reporting by Regional utilities. This process relies on utilities to report their actual and projected fuel availability along with alternate fuel capabilities, to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output, depending on the event initiating the reporting process. Data is aggregated at the FRCC and is provided, from a Regional perspective, to the RC, SCEC and governing agencies as requested. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and is quickly integrated into an enhanced Regional Daily Capacity Assessment Process along with various other coordination protocols to ensure accurate reliability assessments of the Region and also ensure optimal coordination to minimize impacts of Regional fuel supply issues and/or disruptions.

Fuel reliability continues to be adequate for the region and fuel supplies are expected to be sufficient including periods of extreme weather during peak load conditions. There are no identified fuel reliability issues at this time. Based on current fuel diversity, alternate fuel capability and fuel reliability analysis results, the FRCC does not anticipate any fuel reliability issues including fuel transportation issues affecting capability during peak periods and/or extreme weather conditions.

Assessment Area Description

FRCC's membership includes 30 Regional Entity Division members and 24 Member Services Division members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. The FRCC Region is typically summer peaking and divided into 10 Balancing Authorities. As part of the transition to the ERO, FRCC has registered 72 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC website.[101]

100 https://www.frcc.com/handbook/Shared%20Documents/EOP%20%20Emergency%20Preparedness%20and%20Operations/FRCC%20Communications%20Protocols%20102207.pdf.

101 https://www.frcc.com/default.aspx.

MISO

Introduction

The Midwest Independent Transmission System Operator's (MISO) Planning Authority region covers 750,000 square miles, spread across 13 states. MISO's Midwest Energy and Operating Reserves market includes 347 market participants who serve over 40 million people. MISO experiences its annual peak during the summer season.

MISO market participants use the Module E Capacity Tracking (MECT) tool to submit its forecasted Demand and Resources at each Load Commercial Pricing Node for the upcoming Planning Year. These forecasts are then aggregated to determine the MISO regional demand, generation, and Reserve Margin forecasts. The latest MISO Commercial Model is used for calculation of *Existing-Other* capacity resources

Coordination amongst several MISO departments occurs to provide accurate forecast information for each section of the report. Load and resource forecasts are provided in the Demand and Generation sections, and transmission and operational concerns are identified in the Transmission and Operation Issues sections.

Demand

The demands as reported by Load Serving Entities (LSE) are weather normalized, or 50/50, forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50 percent chance the actual load will be higher and a 50 percent chance the actual load will be lower than the forecast. Historically, reported load forecasts have been highly accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions. During last year's winter season, MISO experienced an instantaneous peak of 91,367 MW on December 13th hour ending 19:00 EST. The instantaneous load is the highest value metered during the peak hour.

Last year's unrestricted non-coincident demand forecast of 93,836 MW is 12 percent higher than this year's unrestricted non-coincident demand forecast of 83,719 MW for December 2011. This difference is mostly due to First Energy's exit from MISO effective June 2011.

Table 21: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**79,994**	**December-2011**
2010/2011 Forecast	91,310	January-2011
2010/2011 Actual	91,367	December-2010
All-Time Peak	91,367	December-2010

An unrestricted non-coincident peak demand is created on a regional basis by summing the coincident monthly forecasts for the LSE in the larger regional area of interest. Using historic market data, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority and comparing them against the system peak. This produced an estimated diversity of 3,725 MW; therefore, the MISO is able to estimate a total internal demand of 79,994 MW.

MISO bases its resource evaluation on the actual market peak. MISO currently separates Demand Resources into two separate categories, Interruptible Load and Direct Controlled Load Management (DCLM). Interruptible load of 2,330 MW (3 percent of Total Internal Demand) for this assessment is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator (Table 22). DCLM of 235 MW (0.3 percent of Total Internal Demand) for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." The Resource Adequacy processes as set forth in Module E of MISO's tariff[102] acts as the measurement and verification tool for demand response.

Table 22: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**-**
Non-Controllable Demand-Side Management	
Direct Control Load Management	235
Contractually Interruptible (Curtailable)	2,330
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	2,066
Total Dispatchanle, Controllable Demand Response	**4,631**
Total Demand-Side Management	**4,631**

MISO does not currently track Energy Efficiency programs; however, they may be reflected in individual LSE load forecasts. To account for uncertainties in load forecasts, MISO applies a probability distribution, Load Forecast Uncertainty (LFU), to consider a larger range of forecasted demand levels. LFU is derived from variance analyses to determine how likely forecasts will deviate from actual load. There have not been any changes made due to the economic downturn in both the load forecast method/assumptions and the impact to the actual forecast.

Generation

Last year's Existing (Certain, Other, and Inoperable) capacity of 144,961 MW is 9 percent higher than MISO's projected Existing capacity of 132,397 MW for the upcoming winter season. This difference is mostly due to First Energy's exit from MISO effective June 2011, which accounts for approximately 11 percent MW reduction from last year's forecast.

MISO projects 289 MW for Future (Planned and Other) capacity over the assessment timeframe. Of the Existing and Future capacity, it is difficult to predict the wind capacity available on peak due to the intermittent nature of wind. However, the MISO determined maximum wind capacity credits using an Equivalent Load Carrying Capacity (ELCC), a metric commonly utilized by the National Renewable Energy Laboratory (NREL). The MISO used the ELCC for wind generation and Loss of Load Expectation analyses.[103] Wind shows an *Existing-Certain* capacity of 481 MW on peak over the assessment

[102] https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx.

[103] https://www.midwestiso.org/Library/Repository/Study/LOLE/2010%20LOLE%20Study%20Report.pdf.

timeframe utilizing a 12.9 percent capacity credit for those resources committed as Planning Resource capacity to the MISO within the Module E Capacity Tracking (MECT) tool. It is important to note that not all Existing wind capacity was committed in the MECT. *Existing-Other* capacity for wind is 680 MW expected on peak and 8,187 MW derates on peak over the assessment timeframe (Table 23). Hydro shows an *Existing-Certain* capacity of 2,210 MW expected on peak over the assessment timeframe. The *Existing-Other* capacity for hydro is 270 MW expected on peak and 213 MW derates on peak over the assessment timeframe. Of the Existing and Future capacity, biomass shows 244 MW on peak throughout the assessment timeframe. MISO anticipates 2,066 MW of Behind-the-meter Generation (BTMG) and 49 MW of Demand Response Resources (DRR) to be available for the winter season. Hydro conditions for the winter appear normal and there are no reports of reservoir levels showing insufficiencies to meet both peak demand and the daily energy demand throughout the winter. MISO has no reports experiencing or expecting conditions (i.e. weather, fuel supply, fuel transportation) that would reduce capacity.

Table 23: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	481
	Derated	8,187
	Wind - Total Nameplate Capacity	**8,668**
Solar	Expected	-
	Derated	-
	Solar - Total Nameplate Capacity	**-**
Hydro	Expected	3,210
	Derated	-
	Hydro - Total Nameplate Capacity	**3,210**
Biomass	Expected	148
	Derated	-
	Biomass - Total Nameplate Capacity	**148**

Capacity Transactions

The MISO only reports power imports (not exports) to the MISO market or reported interchange transactions into the MISO market. The forecast reflects 3,087 MW of power imports from year-to-year (Table 24).[104] All these imports are firm and backed by firm transmission and firm generation. No import assumptions are based on partial path reservations. There are no transactions with Liquidated Damages Contract (LDC) clauses or “make-whole” contracts that are included as firm capacity. The MISO does not intend to rely on outside assistance or external resources for emergency imports for this winter season.

[104] 2011/2012 winter peak power imports obtained from the MECT.

Table 24: On-Peak Capacity Transactions

	Transaction Type	Winter 2011/2012 (MW)
Imports	Firm	3,087
	Expected	-
	Non-Firm	-
	Total	**3,087**
Exports	Firm	-
	Expected	-
	Non-Firm	-
	Total	**-**
	Net Transactions	**3,087**

Transmission

The following projects were put in service since last winter season to enable reliable and efficient transmission service for the MISO region. Ninety-six miles of new 161 kV line in ITC Midwest (ITCM) and Xcel Energy (XEL), forty miles of new 138 kV line in American Transmission Company, Michigan Electric Transmission Company (METC), and Ameren Missouri, and forty-eight miles of new 115 kV line in Minnesota and XEL have been put into service. Also, thirty-seven miles of 345 kV line outlets in Ameren Illinois connecting Prairie State Power Plant to the existing Baldwin Stallings 345 kV line were put in service in December 2010. These projects will be in areas of American Transmission Co., Ameren Missouri, Great River Energy, ITC Midwest, and Vectren. At this time no major upgrades are anticipated to come into service during the upcoming winter season. Major upgrades to MISO transmission system that have occurred since the beginning of the 2011 Summer Season (June 1, 2011) are shown below (Table 25). MISO does not anticipate any existing, significant transmission lines or transformers being out-of-service through the winter season. At this time it is premature to determine whether MISO will have any transmission constraints that could significantly impact reliability. Interregional transmission transfers are not available at this time.

Table 25: Recent Transmission Upgrades[105]

NERC Region	Transmission Owner	Project Name	Maximum Voltage (kV)	Project Description
MRO	XEL	Build 18 miles 115 kV line from Glencoe - West Waconia	115	Build 18 miles 115 kV line from Glencoe - West Waconia
MRO	ITCM	Glenworth 161/69kV (Glenville Area)	69-161	Construct a new 161/69kV 100 MVA substation tapping the Hayward-Worth County 161 kV line. ITC will construct the 161kV portion including the TRF and low side protection. DPC will construct the 69kV portion.
RFC	ITC	B3N Interconnection	220	Returns the Bunce Creek to Scott 220 kV circuit to service, and replaces the Phase Angle Regulator with 2 new phase angle regulating transformers in series
SERC	Ameren	Big River-Rockwood 138 kV	138	Big River-Rockwood 138 kV - Construct new line
MRO	XEL	G349, 37774-01. Upgrades for G349	345	G349 Upgrades: Yankee substation, Brookings Co 345/115 substation, Hazel Run 53 MVAr capacitor, Brookings-Yankee 115 kV line
RFC	METC	Tihart - Oakland (Genoa) 138kV	138	Replace all line structures and insulators.

105 Reflects all projects that have been put into service since the start of the 2011 summer season.

Operational Issues

MISO is not anticipating any unusual operating conditions during the 2011/2012 winter season and has not undertaken any studies to determine the impacts of potentially adverse conditions.

FERC has recently accepted a MISO proposal to create a new resource type by which intermittent resources can register, called Dispatchable Intermittent Resources (DIR). The increase in the amount of Intermittent Resources, and the limitations that currently exist with respect to modeling, dispatching, and pricing have corresponding impacts on MISO system operations and market performance. The proposed new DIR resource type, and the related Tariff changes, is intended to address market and operational issues relating to the manual curtailment of Intermittent Resources, and to increase the participation of wind generators and other similar Intermittent Resource types in the Energy and Operating Reserves Market.

The new resource designation took effect on March 1, 2011 which allowed newly registered DIRs to begin participating in MISO's markets on June 1, 2011. Approximately 1,200 MW of DIRs registered for the June 1st implementation and an additional 800 MW registered for the September 1st quarterly model. MISO anticipated additional DIRs to register each quarter up to the two year timeframe (June 1, 2013) for complete registration of DIRs required to register.

MISO does not anticipate experiencing any reliability concerns as a result of minimum demand or over generation during the winter period. However, if those conditions do occur, MISO has a Minimum Generation Event Procedure[106] that clearly identifies actions to be taken to effectively manage these conditions.

MISO has no concerns regarding the response of any demand response resources (DRRs) that are deployed during the winter period. Given the currently limited use of such resources in the MISO markets, the impact from any performance issues would be relatively minor. In the event that such resources are part of a plan being utilized to mitigate a capacity shortage situation, the MISO's Capacity Emergency Procedure identifies the actions to be taken to effectively manage such conditions, including emergency energy purchases and utilization of operating reserves.

The number of times that a demand response resource could be deployed during any period would be restricted by the type of resource and its offer parameters.[107]

MISO does not foresee any impact to reliability during the upcoming winter period from environmental and/or regulatory restrictions. MISO is, however, considering the possible impacts from various future scenarios to understand the longer-term effects that these types of restrictions could potentially have on the managed resources.

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[106] https://www.midwestiso.org/Library/Repository/Procedure/RTO-EOP-002%20Midwest%20ISO%20Market%20Footprint%20and%20Sub-Area%20Capacity%20Emergencies%20Procedure.pdf.

[107] For a DRR Type II, the combination of its "Minimum Run Time" and "Minimum Down Time" once deployed would restrict the resource's availability for deployment during the remainder of the period. Similarly, for a DRR Type I, the combination of its Minimum Interruption, Minimum Duration and Minimum Non-Interruption Interval would do the same.

Reliability Assessment

The goal of a Loss-of-Load-Expectation (LOLE) study is to determine a level of reserves which ensures that the probabilities for loss of load within the MISO system over each integrated peak hour for the planning period sum to 1 day in 10 years or 0.1 days/year.[108,109]

According to the 2011 LOLE study, the Reserve Margin requirement calculated for the MISO is 17.4 percent of MISO Net Internal Demand[110] of its market area for the 2011/2012 winter season. In addition to the 107,420 MW of *Existing-Certain* capacity resources, MISO expects 3,087 MW of external resources, 2,066 MW of BTMG, and 49 MW of DRR which are available to serve load.[111] BTMG is considered a capacity resource when calculating the MISO Reserve Margin. This additional capacity arrives at a total designated capacity of 112,573 MW and brings the projected Reserve Margin for MISO to 35,144 MW, which is 45.4 percent of MISO Net Internal Demand.

For NERC reporting, there are three Reserve Margins, which are Existing, Deliverable, and Prospective. In addition to the 107,420 MW of *Existing-Certain* capacity resources, MISO expects 3,087 MW of external resources. This additional capacity arrives at a total capacity of 110,507 MW. MISO expects 235 MW of Direct Control Load Management (DCLM), 2,330 MW of Interruptible Load (IL), and 2,066 MW of BTMG. These three supply-side demand response mechanisms, DCLM, IL, and BTMG reduce total internal demand to 75,363 MW of net internal demand. This brings the projected *Existing-Certain* and Net Firm Transactions Reserve Margin to 35,144 MW, which is 46.6 percent of net internal demand. Adding 260 MW of *Future-Planned* resources brings the projected Deliverable Reserve Margin to 47 percent. Adding *Existing-Other* capacity minus wind and hydro derates brings the projected Prospective Reserve Margin to 66.7 percent. MISO's projected Reserve Margin is higher than the 17.4 percent MISO system planning Reserve Margin requirement. Firm load curtailment is a very low probability event for the 2011/2012 winter period.

For inclusion in seasonal assessments, the MISO utilizes Energy Information Administration fuel forecasts to identify any system wide fuel shortages. No fuel shortages are projected for the winter period. In addition to the seasonal assessments the MISO's Independent Market Monitor submits a monthly report to the MISO's Board of Directors which covers fuel availability and security issues. During the operating horizon, the MISO relies on market participant to anticipate reliability concerns related to the fuel supply or fuel delivery. Since there are no requirements to verify the operability of backup fuel systems or inventories, supply adequacy and potential problems must be communicated appropriately by the market participants to enable adequate response time. MISO has not performed any dynamic and static reactive power studies for the upcoming winter season.

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[108] https://www.midwestiso.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf.

[109] Refer to Table 3-5 of the 2010 LOLE Study Report for a comparison of Planning Year 2011 planning Reserve Margin (PRM) to last year's PRM.

[110] MISO Net Internal Demand is Total Internal Demand less DCLM and IL (77,429 MW).

[111] External, BTMG, and DRR values are based on forecasted 2011-2012 winter values from Module E.

Assessment Area Description

MISO,[112] a Planning Authority,[113] operates as a single Balancing Authority and experiences its annual peak during the summer season. MISO's scope of operations covers 750,000 square miles, which includes 13 states. MISO's Midwest Energy and Operating Reserves market includes 347 market participants who serve over 40 million people.

[112] MISO can be reached at: http://www.midwestiso.org.

[113] A NERC Planning Authority is defined as the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf.

MRO

Executive Summary

MRO Introduction

As with the NERC 2011 Summer Assessment and the NERC 2011 LTRA, the NERC 2011/2012 Winter Assessment will be the first winter assessment to be implemented across the newly defined Reporting Areas. In previous winter assessments, the MRO had two sub-regions, defined as MRO-US and MRO-Canada. MRO previously collected data from the individual utilities, companies, and Registered Entities within the MRO footprint and summed the data to reflect a total for the two sub-regions and the MRO region as a whole. However, the MRO-US and MRO-Canada sub-regions were not congruent or compatible with Planning Authority and/or ISO/RTO footprints. This was less than desirable when comparing Reserve Margins and other planning and operating information. Data reported for this reliability assessment and future assessments will be "Reporting Area" centric. Reporting Areas will be based on ISO, RTO and/or Planning Authority footprints, and the data will be kept whole to improve the accuracy of the report. For the NERC 2011/2012 Winter Assessment, the MRO collected narrative information and data from the four Planning Authorities that are now designated as Reporting Areas in the NERC assessments:

- Midwest Independent Transmission System Operator (MISO)
- Midcontinent Area Power Pool (MAPP)
- Saskatchewan Power (SaskPower)
- Manitoba Hydro

Since the MISO footprint is geographically contained and registered within three Regional Entities (MRO, SERC, and RFC), each of these three Regional Entities review the MISO section of this report.

Because the sum of the four Planning Authority footprints are not congruent with the MRO footprint, an MRO total for demand and generation is not reported in this year's report as it has been in past years. The reliability assessments for 2011 will establish new benchmarks for comparing this year's newly-defined Reporting Areas with future year assessments.

Demand, Capacity, and Reserve Margins Summary

The MISO membership has changed since the 2010/2011 Winter Assessment. As noted within the MISO section of this report, First Energy and Cleveland Public Power consolidated into the PJM RTO on June 1, 2011. In addition, Duke Energy Ohio and Duke Energy Kentucky plan to consolidate into the PJM RTO on January 1, 2012.

The demand projections over the assessment timeframe have been affected by changes in the MISO membership. MISO's Total Internal Demand and Net Internal Demand for MISO's expected peak winter month December of 2011 are forecasted to be 79,994 MW and 75,363 MW respectively, which are down from last year's winter forecast of 91,310 MW and 84,894 MW respectively. The majority of this demand reduction is due to the exit of First Energy. The forecasts for January and February of 2012, when compared to December 2011, are approximately 5 percent and 9 percent lower respectively due to the exit of the Duke companies.

MISO forecasts *Existing-Certain* capacity to be 107,420 MW for December of 2011, a 13 percent decrease compared to the prior year. The majority of this resource reduction is due to First Energy's departure from MISO. Net firm transactions are expected to bring 3,087 MW of capacity as well as Future and *Conceptual* resources anticipated to be in service by the winter season of 289 MW of capacity. Of those resources, Future nameplate wind generations are expected to account for approximately 168 MW. For the 2011/2012 winter assessment period, the Deliverable Capacity Resources Reserve Margin is in excess of the NERC target Reserve Margin of 15 percent for MISO at 47 percent.

The 2010/2011 winter Mid-continent Area Power Pool (MAPP) actual non-simultaneous peak demand was 4,771 MW. This coming winter's peak demand forecast is 5,036 MW. The Existing MAPP capacity resources for the 2011/2012 winter season are 7,584 MW. All projected Reserve Margins in MAPP for the 2011/2012 winter season are expected to be well in excess of the MAPP target Reserve Margin requirements of 15 percent for predominately thermal systems, and 10 percent for predominately hydro systems.

Within Manitoba Hydro, total internal demand projections range between 4,276 and 4,477 MW during the 2011/2012 winter season. *Existing-Certain* capacity resources range between 5,653 MW to 5,709 MW during the assessment timeframe. *Existing-Certain* capacity resources range between 5,078 MW to 5,303 MW. Approximately 11 MW of additional *Existing-Certain* capacity resources will be added by the end of 2011.

Month to month Reserve Margins have been projected to be no less than 22.9 percent during the winter season. Manitoba Hydro has Reserve Margin criteria requiring a minimum of 12 percent reserve above forecast peak demand and the projected Reserve Margins are still well above this minimum Reserve Margin requirement.

Saskatchewan's 2010/2011 winter peak demand forecast was 3,133 MW. This year's 2011/2012 winter peak demand forecast is 3,391 MW. Approximately 3,986 MW of total existing capacity resources are expected to be available to serve this peak. Saskatchewan's projected Reserve Margin is expected to be between 15.7 percent and 18.1 percent. Their target Reserve Margin is 13 percent.

Transmission Summary

Within MISO, approximately 220 miles of new transmission have been put into service since the previous winter season.

Within the MAPP Planning Authority footprint several new lines have come into service since last season and more are expecting to be built through the 2011/2012 winter assessment period.

This winter, Manitoba Hydro will be installing transmission facilities required to deliver the Wuskwatim Generating Station (Generation service date is spring 2012). These include:

- A new Thompson Birchtree 230 kV Station and 28 miles of 230 kV line from Thompson Birchtree-Wuskwatim.

- Two 85 miles, 230 kV lines between Wuskwatim and Herblet Lake, and
- One 99 miles, 230 kV line from Herblet Lake to The Pas Ralls Island.
- A 150 MVAr Static VAr Compensator (SVC) will be installed at the Thompson Birchtree 230 kV Station to provide transient voltage support.

Within SaskPower, there are no new significant BES transmission lines, transformers, or substation equipment being installed since the 2011 summer assessment.

Operations Summary

With respect to Operations, there are no foreseeable challenges facing the operation of the bulk power systems within the MISO, the MAPP, the Manitoba Hydro, or the SaskPower footprints. Within Manitoba Hydro, commissioning of the new Wuskwatim Transmission facilities will be the most important new activity this winter outside of normal operations.

Entering the winter season, nameplate wind generation reported by the four Planning Authorities totals 10,189 MW. An additional 1,300 MW of nameplate wind generation is expected to come into service by the end of February 2012. Each Planning Authority assumes different availability at peak demand. The MISO, as the Reliability Coordinator for its Planning Authority footprint as well as MAPP's footprint manages the majority of this wind generation. Additional detail on wind generation management is included within the MISO section of the report.

MRO–Manitoba Hydro

Introduction

Manitoba Hydro is a Provincial Crown Corporation providing electricity to 521,600 customers throughout Manitoba and natural gas service to 261,150 customers in various communities throughout southern Manitoba. Manitoba Hydro also has formal electricity export sale agreements with more than 35 electric utilities and marketers in the Midwestern U.S., Ontario, and Saskatchewan.

Manitoba Hydro is its own Planning Authority and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, with MISO performing the Reliability Coordinator function.[114]

Demand

The demand forecast adjusts historical load to remove the weather effect for the purpose of forecasting future load. Normal weather for the forecast prepared July 2011 was based on 25 years of Winnipeg temperatures from April 1986 to March 2011. Economic forecast assumptions were taken from the 2011 Economic Outlook and the 2011 Energy Price Outlook. These documents contain Manitoba Hydro's forecasts of economic variables including prices of electricity, natural gas and oil, Gross Domestic Product (GDP), Manitoba population, and housing.

The actual peaks for the months of December 2010, January 2011, and February 2011 were: 4,206 MW, 4,299 MW, and 4,255MW respectively. This winter's total internal demand forecast for the months of December 2011 through February 2012 are 4,276 MW, 4,477 MW, and 4,283MW respectively (Table 26).

Table 26: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**4,477**	**January-2012**
2010/2011 Forecast		
2010/2011 Actual	4,299	January-2011
All-Time Peak	4,477	January-2009

Manitoba Hydro maintains a Curtailable Rate Program; however, it is not intended to reduce the peak demand but rather to meet reliability obligations. Manitoba Hydro will curtail customers in response to system emergencies and to maintain operating reserves. As a percentage of Total Internal Demand, the total effects of demand response that can reduce peak demand ranges from, 5 percent to 5.3 percent during the assessment period.

Upon experiencing certain system contingencies or an emergency, the System Control Centre may curtail the customer by the terms of the contracts agreed upon in the Curtailable Rates Program.[115]

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[114] Manitoba Hydro collects data from various sources including: historical operating data, data from neighboring utilities, physical equipment data, forecast data generated from internal and external computer models that integrate various data sources, and internal and external reports. Analysis methods include industry accepted practices using computer models.

Manitoba Hydro employs a Power Smart[116] portfolio which includes customer service, cost-recovery, incentive-based and rate-based initiatives and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of energy-efficiency, conservation, load management and customer self-generation programs, is designed to help customers conserve energy, reduce energy bills and protect the environment.

The measurement and verification activities conducted by Manitoba Hydro are tailored to the specific requirements of each energy efficiency program/sector. The intensity of measurement and verification is based upon variability of usage and the benefit of measurement in relation to the cost.

- The residential market is characterized by a large volume of customers with typically homogeneous energy usage patterns. Due to the size and homogeneity of the sector, measurement and verification is minimal.[117]
- The commercial market is characterized by fewer customers with typically homogeneous usage patterns. Measurement and verification is limited due to cost/benefit implications and the ability to use deemed savings and standardized usage patterns based on technologies.
- The industrial market includes programs which will establish an appropriate measurement and verification plan for each customer. The plan will follow the principles outlined in the International Performance Measurement and Verification Protocol – Volume 1 (March 2002).

The Evaluations department within Manitoba Hydro models evaluations according to the International Performance Measurement and Verification Protocols (IPMVP) from the Efficiency Valuation Organization and DSM best practices. All on-peak Demand-Side Management data for Manitoba Hydro is shown below (Table 27).

Table 27: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**19**
Non-Controllable Demand-Side Management	
Direct Control Load Management	-
Contractually Interruptible (Curtailable)	226
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**226**
Total Demand-Side Management	**245**

[115] The Control Centre measures the amount of curtailment through the EMS/SCADA system and verification is monitored throughout the curtailment. The curtailment is logged and a memo is issued after the fact outlining the extent of the curtailment, the amount curtailed, and the reason for curtailment.

[116] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_86.pdf.

[117] Energy savings are based upon a deemed savings per technology in conjunction with surveyed usage patterns. Deemed savings are normally based on engineering estimates that consider generally accepted values (i.e. those used by other utilities) and historical values.

The standard deviation of the one-year December to February peak forecasts is estimated to be 2.6 percent. Therefore it is expected that the peak in any of those 3 months will be within plus or minus 5.1 percent of the predicted peak 95 percent of the time. This covers all sources of variability, including weather, the economy and other factors.

Economic assumptions are updated every year, and the economic recession has been factored into the last two forecasts. Known load reductions and increases are also factored into the forecast, and the end result is the winter peak forecast similar to last year's forecast.

The projected winter peaks represent a 25-year average coldest weekday for each month. They do not represent the extreme single year coldest weekday. However, the standard deviation estimate of 2.6 percent for the peak indicates that an extreme winter condition would be about 5 percent higher than the average peak.

Generation

During the 2011/2012 winter assessment period, *Existing-Certain* capacity ranges from 5,078 MW to 5,303 MW. Other capacity resources are expected to range from 385 to 631 MW. No resources are expected to be inoperable during the winter season. Future capacity additions are projected to be 11 MW.

Included in the *Existing-Certain* capacity above is the Jenpeg Generation Station (GS), with associated nameplate of 131 MW. The expected on-peak amounts for Jenpeg GS range from 94 MW to 110 MW during the 2011/2012 winter assessment period. This hydro station is considered as variable generation because it is run-of-the-river and is considered an energy resource because its output can only be modified for a 24 hour period. These on-peak capacity values are calculated based on the MRO Generator Testing Guidelines[118].

Manitoba Hydro purchases the output from two existing variable capacity resources. These two resources, the St. Leon and St. Joseph wind plants, have nameplate capacities of 104 MW and 138 MW respectively, totaling 242 MW. Although Manitoba Hydro has contractual rights to all capacity from these facilities, Manitoba Hydro does not count wind resources for winter reliability/capacity purposes. Future wind resources include a 16.5 MW (nameplate) expansion to the St. Leon wind plant planned for 2012. There is no biomass generation on the Manitoba Hydro system (Table 28).

[118] http://www.midwestreliability.org/REL_asr.html.

Table 28: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	-
	Derated	242
	Wind - Total Nameplate Capacity	**242**
Solar	Expected	-
	Derated	-
	Solar - Total Nameplate Capacity	**-**
Hydro	Expected	4,906
	Derated	-
	Hydro - Total Nameplate Capacity	**4,906**
Biomass	Expected	-
	Derated	-
	Biomass - Total Nameplate Capacity	**-**

Reservoir levels are sufficient to meet both peak demand and daily energy demand. Manitoba Hydro has no known concerns or expected conditions that would reduce capacity. Manitoba Hydro expects no significant generating units to be out of service or retired during the winter season.

Capacity Transactions

Manitoba Hydro has 500 MW of firm on-peak capacity imports projected for the 2011/2012 winter season. No non-firm on-peak capacity imports are projected. There are no plans or expectations to negotiate any more capacity on-peak import contracts before the end of the winter season. All of Manitoba Hydro's imports are backed by firm contracts for both generation and transmission.

Manitoba Hydro has 580 MW of firm on-peak capacity exports project for the 2011/2012 winter season. No non-firm on-peak capacity exports are projected (Table 29). There are no plans or expectations to negotiate any more capacity on-peak export contracts before the end of the winter season. All of Manitoba Hydro's exports are backed by firm contracts for both generation and transmission.

Table 29: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	500
	Expected	-
	Non-Firm	-
	Total	**500**
Exports	Firm	580
	Expected	-
	Non-Firm	-
	Total	**580**
	Net Transactions	**(80)**

All of Manitoba Hydro's firm on-peak capacity import and export contracts contain liquidated damage clauses and are "make-whole" as defined by FERC Order No. 890.

Manitoba Hydro participates in the MISO's contingency reserve sharing pool. The MISO's contingency reserve sharing pool is made up of 2,000 MW of reserves. Manitoba Hydro is required to carry 150 MW of these reserves.

Transmission

New transmission facilities were required to accommodate the new Wuskwatim Generating Station. These facilities include:

- A 26 mile 230 kV line from Birchtree Lake to Wuskwatim (W76B)
- An 85 mile 230 kV line from Wuskwatim to Herblet Lake (W73H)
- A second 85 mile 230 kV line from Wuskwatim to Herblet Lake (W74H)
- A 103 mile 230 kV line from Herblet Lake to Ralls Island (H75P)

For Wuskwatim, a 150 MVAr Static VAr Compensator (SVC) will be installed at the Thompson Birchtree 230 kV station to provide transient voltage support. The SVC and the Bank 1 transformer at Birchtree Station that supports the SVC will be in service by the start of the winter season.

Manitoba Hydro expects to meet the in-service dates for the Wuskwatim transmission facilities. Manitoba Hydro does not anticipate any significant transmission lines or transformers being out of service through the 2011/2012 winter season. Manitoba Hydro does not foresee any transmission constraints that could significantly impact reliability.

There is a request of a 6 week outage to the 230 kV Circuit L20D (Oct 15th to Nov 30th, 2011). This outage will impact transfer limits for the Manitoba to USA interface. Operating guides are developed to ensure reliability of the interconnected power grid.

All Manitoba Hydro transfer capabilities with neighboring utilities are determined in accordance with NERC, Regional, and Manitoba Hydro reliability standards and criteria such that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency and specified multiple contingencies. These studies consider simultaneous transfers and transmission and generation constraints.

- **Manitoba Hydro – United States** (MH-USA) interconnecting tie line transfer limits are developed through joint studies with the Interconnected Study Working Group (ISG).
- **Manitoba Hydro – Ontario** (MH-Hydro One) interface transfer capability is determined from separate analyses conducted by Manitoba Hydro's System Performance department and by Ontario Independent Electricity System Operator (IESO) and is also coordinated with the latest analysis and guides from the Manitoba–Ontario – Minnesota (MOM) interconnection working group.
- **Manitoba Hydro – SaskPower** (MH-SP) interconnecting tie line transfer limits are developed through joint studies by the two utilities on a semi-annual (winter and summer season) basis. Analyses are conducted to determine interface transfer capabilities for the most probable operating configurations. These analyses also examine sensitivities of the transfer capabilities to variances in major network parameters on both sides of the interface.

Operational Issues

On no less than an annual basis, Manitoba Hydro performs an operational study to determine storage reserve requirements necessary to meet demand under the lowest historic hydro flow on record and a high load forecast.

There have been no unique operational problems observed. Manitoba Hydro has no new operating procedures resulting from integration of variable resources. No reliability concerns are expected due to minimum demand and over generation. Manitoba Hydro is currently performing operational studies for the new generator interconnection of Wuskwatim.

Curtailable load is not used to meet peak demands. Manitoba Hydro does have restrictions as to how many times demand response can be deployed. Quarterly reports are sent to Manitoba Hydro's System Control to apprise them of the number of curtailments which have occurred to date and how many remain.

There are no environmental and/or regulatory restrictions that are expected to impact reliability. Manitoba Hydro does not anticipate any unusual operating conditions that could significantly impact reliability for the upcoming winter season.

Reliability Assessment

Existing Reserve Margins are projected to range between 22.9 percent and 27.9 percent during the winter assessment period. Anticipated and Prospective Reserve Margins are projected to range between 23.1 percent and 28.2 percent. These Reserve Margins are well above the minimum Reserve Margin requirement of 12 percent.

As a predominately hydro region, Manitoba has both an energy criterion and a capacity Reserve Margin criterion. These criteria are set based on system historical adequacy performance analysis and with reference to probabilistic resource adequacy studies. The energy criteria requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions on the 96 year hydraulic flow record are repeated. The capacity Reserve Margin criterion requires a minimum 12 percent reserve above the forecast peak demand. Manitoba Hydro performs its own Loss-of-Load Expectation (LOLE) studies and in previous years also participated in MAPP regional LOLE studies.

The MAPP LOLE Study for the Ten-Year Planning Horizon 2010-2019 dated December 30, 2009 included Manitoba in the study region. Manitoba Hydro completed an internal Planned Resource Adequacy Assessment study for the 10-year planning horizon from January 1, 2011 through December 31, 2020 in March 2011.

Projected Reserve Margins have decreased for this winter assessment period compared to last year's. The minimum margin during the period has decreased from 27 percent in 2010 to 22.9 percent in 2011, although 22.9 percent is still significantly above Manitoba Hydro's 12 percent target. The reasons for the reduced margin are an increase in scheduled outages and an increase in forecast domestic load.

Manitoba Hydro does not anticipate any supply or transportation issues for the 2011/2012 winter season. Alberta gas supplies and transportation to Manitoba are plentiful. TransCanada Pipelines Ltd. has been experiencing significant de-contracting of firm transport by its customers. It has more than enough transport available should Manitoba Hydro have to run its gas-fired generation during the winter season. Gas supply is available either from Alberta or from the East via backhaul arrangements. Manitoba Hydro does not have any firm arrangements in place for supply or transport at this time.

Manitoba Hydro has conducted reactive power studies in accordance with NERC VAR-001 standards and identified the required reactive reserves for the province. Reactive power studies have not been refreshed for the winter 2011/2012 winter season, as the standing guide is still valid.

Assessment Area Description

Manitoba Hydro[119] is a provincial Crown Corporation[120] and the sole provider of electricity to 521,600 customers throughout Manitoba. Manitoba Hydro is its own BA. The electricity is transmitted over nearly 62,140 miles of transmission and distribution lines. The length of transmission lines connected to Manitoba Hydro's transmission network includes the following:

- 1,240 miles of 500 kV transmission (AC and HVDC)
- 3,110 miles of 230 kV transmission (AC)
- 870 miles of 138 kV transmission (AC)
- 1,800 miles of 115 kV transmission (AC)

Manitoba is one of ten Canadian provinces and has an area of 250,950 sq mi. Manitoba Hydro is a winter peaking utility.

[119]The website for Manitoba Hydro is http://www.hydro.mb.ca/.
[120] http://hydro.mb.ca/corporate/about_us.shtml.

MRO–MAPP

Introduction

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 and provinces: Iowa, Minnesota, Montana, North Dakota, and South Dakota.[121]

MAPP sends each Load Serving Entity (LSE) in its Planning Authority footprint a seasonal assessment data request to submit its forecasted Demand and Resources for the upcoming season. These forecasts are then aggregated to determine the MAPP regional Demand, Generation, and Reserve Margin forecasts for the upcoming winter season.[122]

Demand

MAPP assumes normal (50/50) weather and normal economic conditions. The 2010/2011 MAPP actual winter peak non-simultaneous demand was 4,771 MW (Table 30). Last winter's demand forecast was 6,050 MW based on the data submitted to MRO. This year's winter peak demand forecast is 5,036 MW. The decrease in the demand forecast from 2010 to 2011 is due to load reporting shifts to the MISO Planning Authority and SPP Planning Authority footprints (approximately 450 MW), and correcting double counting errors (approximately 550 MW). Non-coincident internal peak demands were used to aggregate individual Member loads for use in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions.

Table 30: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**5,036**	**January-2012**
2010/2011 Forecast		
2010/2011 Actual	4,771	February-2011
All-Time Peak	4,932	

A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the winter season. Interruptible Demand (370 MW, 7.3 percent) and Demand Side Management (DSM) (303 MW, 6 percent) programs, amount to 13.3 percent of the MAPP Projected Total Internal Peak Demand of 5,036 MW (Table 31). MAPP members utilize various measurement and verification programs for demand response, such as those based upon International Performance Measurement and Verification Protocols (IPMVP). Reductions in demand due to energy efficiency total 23.2 MW, or 0.5 percent of the MAPP Projected Total Internal Peak Demand of 5,036 MW. Energy efficiency is verified through several means, such as use of the Minnesota Deemed Savings Database provided by the Minnesota Office of Energy Security.

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[121] About MAPP section of the MAPP website: http://www.mapp.org.

[122] MAPP also assigns portions of the Seasonal Assessment write-up to its Transmission Operations Subcommittee, including the Transmission, Operations Issues, and Reliability Assessment sections.

Table 31: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**23**
Non-Controllable Demand-Side Management	
Direct Control Load Management	360
Contractually Interruptible (Curtailable)	4
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**364**
Total Demand-Side Management	**387**

Each MAPP member uses its own forecasting method. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns.[123] The continued recession and nation-wide economic downturn continue to negatively impact the load forecast.

Peak demand uncertainty and variability due to extreme weather and/or other conditions are accounted for within the determination of adequate generation Reserve Margin levels. MAPP members utilize a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss of Load Expectation (LOLE) and/or the percentage Reserve Margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10 years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions.

Generation

The Existing capacity resources for the 2011 winter season are 6,907 MW. No Future capacity resources are expected to come into service for the 2011/2012 winter season. These projections do not include firm or non-firm purchases and sales. The month of January was used as the peak winter month in all cases to be consistent. Of the 6,907 MW of Existing capacity resources, 407 MW of wind generation is expected on-peak[124], with a nameplate rating of 1,083 MW. Of the 6,907 MW, 1,840 MW is hydro and 3 MW is biomass capacity (Table 32).

[123] There were no changes in this year's forecast assumptions in comparison to last year.

[124] With respect to existing wind expected on-peak, MAPP utilizes a method that is based on a median of actual wind output. The four peak hours per day for each and every day of the four winter months are used. The size of this dataset is no greater than 10 years, or the life of the wind farm, whichever is less.

Table 32: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	481
	Derated	8,187
	Wind - Total Nameplate Capacity	**8,668**
Solar	Expected	-
	Derated	-
	Solar - Total Nameplate Capacity	**-**
Hydro	Expected	3,210
	Derated	-
	Hydro - Total Nameplate Capacity	**3,210**
Biomass	Expected	148
	Derated	-
	Biomass - Total Nameplate Capacity	**148**

No abnormal operating conditions/restrictions are expected to impact reliability during 2011 winter. MAPP is not experiencing or expecting conditions that would reduce capacity for the 2011 winter season. Hydro conditions for this winter are normal, with reservoir levels back to a normal level after several seasons of low water. MAPP does not anticipate any significant generating units to be out-of-service or retired during the 2011 winter season.

Capacity Transactions

For the 2011 winter season, MAPP is projecting total capacity imports of 390 MW. Of the 390 MW of imports into MAPP, 388 MW are considered firm, none are considered non-firm, and 2 MW are considered Expected.

For the 2011 winter season, MAPP is projecting total capacity exports of 570 MW. These exports are from sources internal to MAPP. Of the 570 MW of exports out of MAPP, 570 MW are considered firm and none are considered non-firm or expected (Table 33).

Table 33: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	388
	Expected	2
	Non-Firm	-
	Total	**390**
Exports	Firm	570
	Expected	-
	Non-Firm	-
	Total	**570**
Net Transactions		**(180)**

For both imports and exports, firm contracts exist for both the generation and the transmission service. Transmission providers within MAPP treat Liquidated Damage Contracts (LDC) according to their tariff policies. Most MAPP members are within non-retail access jurisdictions and therefore liquidated damages products are not typically used. MAPP is forecast to meet the various Reserve Margin targets without needing to include energy-only, uncertain, or transmission-limited resources. No emergency MW are required to meet the Reserve Margin target in MAPP.

Transmission

The BEPC/Western/Heartland Integrated System has energized several new interconnections since the 2010 winter season. In South Dakota, an 11.3 mile 230 kV line was added from Wessington Springs substation to Prairie Winds (Crow Lake). Crow Lake is a new wind farm collector site for 162 MW (108 units at 1.5 MW). The 0.6 mile White–Deer Creek 345kV line is projected to be in service December of 2011.

Northwestern Public Service is working on completion of the new, 14 mile long, Western's Letcher Junction–NWE Mitchell Transmission Substation 115KV line. The line is currently scheduled to be in service by December of 2011. The project will provide additional support to the Mitchell, South Dakota area.

MAPP is not aware of any transmission constraints or transmission issues that will affect system reliability (i.e., deliverability of generation to network load).

Operational Issues

No significant operational issues are expected during the 2011/2012 winter season in the WAPA Upper Great Plains East (WAUE) Balancing Authority (BA). Existing operating guides and temporary operating guides, which are developed as needed, have satisfactorily maintained reliable system conditions throughout 2011. Following high water flood control management, the Missouri River hydro plant release schedules are expected to return to normal by October with normal power plant operations resuming throughout the winter season. Adequate reservoir water will be available for both normal and above normal generation.

The WAUE BA is expected to be able to operate under all load and firm exchange levels while meeting the regional reliability criteria. WAUE anticipates normal levels of demand during the 2011/2012 winter season.

MAPP does not anticipate any reliability concerns from minimum demand or over generation situations. Normal load levels are anticipated for the 2011/2012 winter season and there are no concerns with resource adequacy or demand response in meeting projected peak demands.

Reliability Assessment

All MAPP members have established a planning Reserve Margin target through application of the MAPP Loss of Load Expectation (LOLE) Study. This study was last performed and completed by MAPP on December 31, 2009[125]. The MAPP LOLE study recommends a 15 percent Reserve Margin for predominantly thermal systems, and 10 percent Reserve Margin for predominantly hydro systems.

[125] MAPP Loss of Load Expectation Study 2010-2019, December 2009.

The projected Reserve Margins in MAPP (44 percent Existing, 44 percent Anticipated, and 44 percent Prospective) for the 2011 winter season are in excess of the MAPP target Reserve Margin of 15 percent for predominately thermal systems, and 10 percent for predominately hydro systems. This winter's projected Reserve Margin is 43.9 percent. This compares to last winter's projected Reserve Margin of 28.1 percent. The increase in Reserve Margin this winter is primarily due to changes in the Planning Authority boundaries between MISO and MAPP. Approximately 1,000 MW of demand was transferred to the MISO Planning Authority from the MAPP Planning Authority. However, no generation resources were transferred as a result of the footprint change.

MAPP does not perform an analysis to ensure external resources are available and deliverable. However, in order for imports to be counted as firm capacity, transmission providers within MAPP require purchases from external entities to have firm contracts and firm transmission service available.

MAPP does perform studies that consider known and anticipated fuel supply or delivery issues in its assessment. Because the MAPP footprint has a large diversity in fuel supply, inventory management, and delivery methods, MAPP does not have a specific mitigation procedure in place should fuel delivery problems occur. Resource providers do not foresee any significant fuel supply and/or fuel delivery issues for the upcoming 2011/2012 winter season. Any fuel supply issues that may develop will be handled on a case by case basis.

Various MAPP reliability studies are performed in accordance with the MAPP members Reliability Criteria and Study Procedures Manual.[126]. Transient, voltage and small signal stability[127] studies are performed as part of the near-term/long-term transmission assessments[128]. Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are expected to adversely impact reliability during the 2011/2012 winter season.

Assessment Area Description

The MAPP Planning Authority[129] area covers electric utilities operating in all or parts of the following states: Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota. Currently, the MAPP Planning Authority covers one BA and eighteen LSEs. The MAPP footprint 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.

[126] MAPP Members Reliability Criteria and Study Procedures Manual, November, 2009.
[127] MAPP Small Signal Stability Analysis Project Report, November 2010.
[128] 2011 MAPP System Performance Assessment.
[129] The MAPP website is: http://www.mapp.org/.

MRO–SaskPower

Introduction

Saskatchewan is a province of Canada and comprises a geographic area of 251,700 square miles and approximately one million people. In Saskatchewan, peak demand is experienced during the winter season. SaskPower serves as the Planning Authority and the 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.

SaskPower owns and operates 7,555 miles of transmission and 52 high voltage switching stations. SaskPower operates networked transmission facilities at the 230 kV and 138 kV voltage levels. This extensive network is designed to serve Saskatchewan's large geographic area and widely-dispersed population. The Saskatchewan transmission system is characterized by relatively long 230 kV and 138 kV transmission lines connecting dispersed generating stations to sparsely distributed load supply points. Saskatchewan has transmission interconnections with the provinces of Alberta and Manitoba, and the US state of North Dakota.

Demand

Saskatchewan develops energy and peak demand forecasts based on a provincial econometric model and forecasted industrial load data. Forecasts take into consideration the Saskatchewan economic forecast, historic energy sales, customer forecasts, normalized weather and historical data, and system losses. Method, assumptions and a summary of results are provided in Saskatchewan's annual Load Forecast Report.

Weather has a significant impact on the amount of electricity consumed by non-industrial customers. Due to this weather sensitivity, average daily weather conditions for the last thirty years are used to develop the energy forecast. Peak load is forecasted on a heating season basis and represents the highest level of demand placed on the supply system. One of the primary economic assumptions is that Saskatchewan's customer base will be maintained.

Last year's winter peak forecast was 3,304 MW and the actual value was 3,133 MW. The 2011/2012 winter peak demand forecast is 3,391 MW (Table 34).

Table 34: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**3,391**	**December-2011**
2010/2011 Forecast	3,304	December-2010
2010/2011 Actual	3,133	February-2011
All-Time Peak	3,156	December-2009

Coincident hourly peak is used in resource evaluations in Saskatchewan. Saskatchewan has Direct Control interruptible demand contracts with customers. Contractually interruptible demand is approximately 3 percent of Total Internal Demand. Saskatchewan has established evaluation measures based on standard industry protocols for demand response verification.

Saskatchewan has energy efficiency programs designed to help customers save power, save money and help the environment. These programs include energy-efficiency, conservation, education, and load management programs. Residential programs focus on consumer education on energy efficiency and market transformation of lighting, appliances and furnace motors including retailer/ manufacturer partnerships and end-user incentives. Commercial and industrial programs include energy performance contracting, energy audits, and information services along with the market transformation of lighting, geothermal and Heating, Ventilating, and Air Conditioning (HVAC). Measurement and verification programs are based on industry standard protocols. All related on-peak Demand-Side Management (DSM) data for Saskatchewan is shown below (Table 35).

Table 35: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**-**
Non-Controllable Demand-Side Management	
Direct Control Load Management	-
Contractually Interruptible (Curtailable)	87
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**87**
Total Demand-Side Management	**87**

Saskatchewan develops annual energy and peak demand forecasts based on a provincial econometric model and forecasted industrial load data. The economic forecast provides information on population and household growth, and growth rates for commercial, farm, and oilfield categories. The forecast for the industrial class is based on individual meetings with each customer to record their future load requirements. The provincial econometric model is coordinated with the provincial government to ensure consistency. Summary details are provided in Saskatchewan's annual Load Forecast Report.

High and low forecasts are developed for Saskatchewan to cover possible ranges in economic variations and other uncertainties such as weather using a Monte Carlo simulation model to reflect those uncertainties.[130]

The load forecast method has not changed due to the economic recession. Load forecast assumptions are routinely adjusted based, in part, on economic conditions and forecasts. In cases where economic performance is expected to decline, the impact would be to lower the actual load forecast due to expected decline in industrial load.

[130] This model considers each variable to be independent from other variables and assumes the distribution curve of a probability of occurrence of a given result to be normal. The probability of the load falling within the bounds created by the high and low forecasts is expected to be 90 percent (confidence interval).

Saskatchewan addresses weather uncertainty using a Monte Carlo simulation model that considers a range of weather conditions based on historical observations.

Generation

An average of 3,934 MW of existing capacity resources and 88 MW of Future capacity resources are expected to be in service through the winter season. The existing capacity value includes 196 MW of nameplate wind generation. Of this amount, 20 percent or 39 MW is expected to be available on-peak. For reliability purposes, Saskatchewan considers 20 percent of wind nameplate capacity to be available to meet the winter peak. The calculation of wind capacity credit for supply planning purposes is based on determining the historical wind generation during various peak load conditions. Saskatchewan does not have any biomass generation (Table 36).

Table 36: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	39
	Derated	157
	Wind - Total Nameplate Capacity	**196**
Solar	Expected	-
	Derated	157
	Solar - Total Nameplate Capacity	**157**
Hydro	Expected	850
	Derated	157
	Hydro - Total Nameplate Capacity	**1,007**
Biomass	Expected	-
	Derated	157
	Biomass - Total Nameplate Capacity	**157**

Saskatchewan reservoirs are at normal conditions and regular operating regimes are expected. Reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the upcoming season. Reservoirs are sufficiently large enough to meet daily requirements, and hydrological conditions are expected to be normal during the upcoming season. There are no concerns over fuel supply or fuel transportation. Saskatchewan does not anticipate any significant generating units to be out-of-service or retired during the winter season.

Capacity Transactions

Saskatchewan has no on-peak imports scheduled for the 2011/2012 winter season from other Reporting Areas that will affect Saskatchewan's capacity margin. Saskatchewan does not rely on emergency imports. Saskatchewan has no on-peak imports scheduled for the 2011/2012 reporting period to other regions or subregions that will affect Saskatchewan’s capacity margin.

Transmission

There were no new significant BES transmission lines, transformers, or substation equipment installed since the 2010/2011 winter season. There are no internal or external transmission constraints expected to impact reliability.

Saskatchewan performs joint seasonal operating studies with Manitoba for the MRO-Canada region to define transfer capability for Saskatchewan. Import capabilities may be referenced on the SaskPower OASIS. The studies consider simultaneous transfers and transmission and generation constraints. MRO interregional transmission transfer capability is addressed by the Eastern Interconnect Reliability Assessment Group (ERAG) study.

Operational Issues

There are no special operating studies or procedures required for this 2011/2012 winter season. No reliability concerns are anticipated related to minimum demand or for over generation conditions.

No environmental or regulatory restrictions have been identified at this time that could potentially impact reliability in Saskatchewan. No unusual operating conditions that could significantly impact reliability are anticipated.

Reliability Assessment

Reliability assessments are performed by SaskPower planning and operating areas are using the following internal reference documents:

- SaskPower 2011 Supply Development Plan
- SaskPower 2011 Load Forecast Report
- SaskPower's NERC Winter Assessment Data Reporting Form ERO-2011W
- Manitoba Hydro - Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability

Saskatchewan uses a probabilistic method of establishing planning reserve (Expected Unserved Energy). Saskatchewan performs an annual Expected Unserved Energy (EUE) analysis to determine the requirement for adding new generation resources. Saskatchewan’s EUE studies result in a target planning Reserve Margin of approximately 13 percent. This winter’s projected Reserve Margin is between 15.7 percent and 18.1 percent. Last winter’s projected Reserve Margin was between 19 percent and 20 percent.

Fuel-supply coordination or interruption in Saskatchewan is generally not considered to be an issue due to system design and operating practices.

- Coal resources have firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Typically there are 20 days of on-site stockpile for each of the coal facilities which in total represent approximately 43 percent of total provincial installed capacity. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves range from 30 to 65 days depending on the plant.
- Natural gas resources have firm transportation contracts with large natural gas storage facilities. The Saskatchewan province backs those contracts.
- Hydro facilities/reservoirs are fully controlled by SaskPower.
- Typically, Saskatchewan does not rely on external generation resources.

Saskatchewan does not anticipate any supply transportation or delivery issues. Dynamic and reactive power resources are considered in on-going operational planning studies.

Assessment Area Description

Saskatchewan is a province of Canada and comprises a geographic area of 251,700 square miles and approximately 1 million people. Peak demand is experienced in the winter. SaskPower is the Balancing Authority for the province of Saskatchewan.

NPCC

Executive Summary

The five Northeast Power Coordinating Council, Inc. (NPCC) Reliability Coordinator sub-areas, or subregions, are defined by the following footprints:

- The Maritimes Subregion (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd. and the Northern Maine Independent System Administrator, Inc);
- New England (the ISO New England Inc.);
- New York (New York ISO);
- Ontario (Independent Electricity System Operator); and
- Québec (Hydro-Québec TransÉnergie).

Demand, Capacity & Reserve Margins

Comparisons of the 2011/2012 winter projections, versus the 2010/2011 winter forecasted and actual peak demands are shown below (Table 37).

Table 37: Winter Demand

Winter Season	Maritimes	New England (ISO-NE)	New York (NYISO)	Ontario (IESO)	Québec
	(MW)	(MW)	(MW)	(MW)	(MW)
2011/2012 Forecast	**5,552**	**22,255**	**24,533**	**22,311**	**37,153**
2010/2011 Forecast	5,615	22,085	24,289	22,474	36,945
2010/2011 Actual	5,252	21,060	24,654	22,733	37,717

The forecasted NPCC subregional Reserve Margins for last winter and this winter are shown below (Table 38).

Table 38: NPCC Planning Reserve Margins

Winter Season	Maritimes	New England (ISO-NE)	New York (NYISO)	Ontario (IESO)	Québec
	(MW)	(MW)	(MW)	(MW)	(MW)
2011/2012 Forecast	20.7%	45.1%	47.1%	33.5%	10.6%
2010/2011 Forecast	20.0%	44.7%	63.8%	38.5%	10.4%

When compared with projections for the 2010/2011 winter, the winter-peaking Québec and Maritimes Subregions are projecting Reserve Margins that are similar to last winter. The New York and Ontario Subregions are projecting lower Reserve Margins. However, New York and Ontario are summer-peaking and the winter margins are still large.

In the Québec Subregion, despite an increase of the available capacity due to capacity additions to the Québec system and an upward revision of the forecasted levels of reservoirs due to better than normal inflows in 2011 compared to 2010, the projected Reserve Margin remains about the same. This is explained by a forecasted internal demand increase (+208 MW) and by the mothballing of Tracy fossil fuel G.S. (-450 MW). The Reserve Margin is above the Reference Reserve Margin Requirement of 9.7 percent and should not be of concern for the Area's reliability because of the nature of the power system. In fact, more than 90 percent of generation is hydro. Outage rates are lower than for other types of generation (coal, oil, etc.) and less maintenance is required. Moreover, the Load Serving Entity

(HQD) can rely on additional potential purchases of up to 1,000 MW as designated resources to satisfy Québec internal demand if required.

The Northeast Power Coordinating Council, Inc. has in place a comprehensive resource assessment program directed through Appendix D, "Guidelines for Area Review of Resource Adequacy," of NPCC Regional Reliability Reference Directory 1, "Design and Operation of the Bulk Power System".[131] This document charges the NPCC Task Force on Coordination of Planning (TFCP) to assess periodic reviews of resource adequacy for the five subregions. In assessing each review, the TFCP will ensure that the proposed resources of each subregion will comply with Section 5.2 of Directory 1:

> *"Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."*

These resource assessments are complemented by the efforts of the Working Group on the Review of Resource and Transmission Adequacy (Working Group CP-08), which assesses the interconnection benefits assumed by each NPCC Area in demonstrating compliance with NPCC resource adequacy requirements.[132]

The NPCC real time operating reserve requirements are indicated in the NPCC Directory #5, "Reserve."[133]

The existing certain and resources expected to be added in the NPCC Subregions for the 2011/2012 winter months are shown below (Table 39).

Table 39: 2011/2012 Winter *Existing-Certain* and *Future-Planned* Resources

Winter Season	Maritimes	New England (ISO-NE)	New York (NYISO)	Ontario (IESO)	Québec
	(MW)	(MW)	(MW)	(MW)	(MW)
December-2011	6,359	28,815	34,159	28,782	40,211
January-2012	6,354	30,030	34,329	28,671	40,064
February-2012	6,322	30,074	34,204	29,052	39,885

Capacity additions and retirements include:

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131 http://www.npcc.org/documents/regStandards/Directories.aspx.

132 The CP-8 Working Group conducts such studies at least triennially for a window of five years, and the Working Group judges if the outside assistance assumed by each Area is reasonable.

133 NPCC Directory #5, "Reserve." https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx.

Ontario

Some projects are scheduled to go into service prior to the winter months. This includes the Raleigh Wind Energy Centre (78 MW) and the Becker Cogeneration facility (15 MW) project. Both projects are scheduled to go into service before December 2011. Two coal units (980 MW) at Nanticoke are expected to be shut down by the end of 2011. Two wind projects with a total capacity of 168 MW are scheduled to be in service for January and February 2012.

Québec

The 768 MW Eastmain-1-A hydro G.S. has recently been placed in-service and Québec is preparing to commission the 150 MW La Sarcelle hydro G.S.

No large capacity additions are anticipated during this winter in the Maritimes, New England or New York subregions.

Installed wind capacity and wind adjustment factors based on the existing certain wind capacity and the derated wind capacity are shown below (Table 40)

Table 40: Installed Wind Capacity and Wind Adjustment Factors

Wind Resources	Maritimes	New England (ISO-NE)	New York (NYISO)	Ontario (IESO)	Québec
	(MW)	(MW)	(MW)	(MW)	(MW)
Expected	158	55	393	463	254
Derated	617	63	918	949	803
Total Nameplate	**775**	**118**	**1,311**	**1,412**	**1,057**

Please refer to the individual subregion assessment section for more specific information.

Transmission

The major anticipated 2011/2012 winter system transmission additions are shown below (Table 41).

Table 41: Transmission Additions for the 2011/2012 Winter Season

Maritimes	New England (ISO-NE)	New York (NYISO)	Ontario (IESO)	Québec
(MW)	(MW)	(MW)	(MW)	(MW)
N/A	Second autotransformer at the Deerfield Substation (345/115 kV)	N/A	N/A	Two ±300 MVar Static Var Compensators (SVC) at the Chénier Substation (735 kV)
	Third autotransformer at the Wachusett Substation (345/115 kV)			Series Compensation of 35% Inserted into each of the Jacques-Cartier to Chamouchouane Transmission Lines (circuits 7024 and 7025) (735 kV)
	New Barry substation with one autotransformer (345/115 kV)			

Operations

The following are highlights that should be noted with regard to operations within NPCC during the 2011/2012 winter period:

- Phase angle regulators (PARs) are installed on the Ontario-Michigan interconnection at Lambton TS on the Ontario side and at Bunce Creek TS in Michigan, representing three of the four interconnections with Michigan. The joint operating agreement has been signed between the IESO and the MISO to operate these PARS. However, an approval from the DOE (United States Department of Energy) is still pending on the joint agreement. The operation of these PARs will enable the IESO and the MISO to control the actual flows on the Ontario-Michigan interconnection equivalent to the scheduled flows within the control deadband (+/-200 MW) and therefore, the PARs will further assist in the managing the system congestion.
- In New Brunswick the Point Lepreau generating station (CANDU nuclear-635 MW) will be out of service throughout the winter operating period.
- The Watercure 345/230 kV transformer bank, the Norwalk Harbor – Northport 138kV 1385 NNC 601 cable between New England and Long Island, and the South Mahwah-Waldwick 345 kV J3410 line have returned to service since the 2010/2011 winter operating period.
- The Beck-Packard 230 kV BP76 New York-Ontario tie remains out-of-service for this winter 2011/2012 operating period.
- Synchronous Condenser CS23 at Duvernay substation in the Montréal area, which became unavailable in June 2008.

NPCC–Maritimes

Introduction

The Maritimes Area is a winter peaking system. This area covers approximately 57,800 square miles serving a population of approximately 1.9 million. 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). In the Maritimes Area, New Brunswick and Nova Scotia are Balancing Authorities. The New Brunswick System Operator is the Reliability Coordinator for the Maritimes Area.

For the coming winter period the Maritimes Area does not expect to experience any major reliability issues. In New Brunswick, the transmission system is robust, comprised of a 345 kV transmission ring with additional supporting 230 kV transmissions. In Nova Scotia, the system consists of a 345 kV and 230 kV backbone with underlying 138 kV transmission. No significant new generation or transmission is expected for the coming winter period. Note that the Point Lepreau nuclear generation station outage is continuing and it will be out of service during the entire Winter Assessment period. The projected Reserve Margins for this winter's operating period range from 20 percent to 25.7 percent.

Demand

The Maritimes Subregion is a winter peaking system. The Maritimes Subregion load is the mathematical sum of the forecasted weekly peak loads of the Subregions (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load non-coincidence within the week into account. Economic assumptions are not made when determining load forecasts.

Based on the Maritimes Subregion 2011/2012 demand forecast, a peak of 5,552 MW is predicted to occur for the winter period, December through February. The actual peak for Winter 2010/2011 was 5,252 MW on January 24, 2011, which was 364 MW (6.5 percent) lower than last year's forecast of 5,616 MW (Table 42). The difference can be attributed to a milder than expected winter.

Table 42: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**5,552**	**January-2012**
2010/2011 Forecast	5,616	January-2011
2010/2011 Actual	5,252	January-2012
All-Time Peak	5,716	January-2004

For the NBSO, the load forecast is based on an End-use Model (sum of forecasted loads by use e.g. water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia, the load forecast is based on a 10-year average measured at the major load center, along with analyses of sales history, economic indicators, customer surveys, technological, demographic changes in the market, and the price and availability of other energy sources.

For Prince Edward Island, the load forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

There is between 329 MW and 398 MW of interruptible demand available during the assessment period; there is 387 MW forecasted to be available at the time of the seasonal peak.

The Maritimes Subregion is broken up into Subregions and each area has its own energy efficiency programs.[134] These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heat as the Maritimes Subregion is a winter peaking system.

In addition the Maritimes does not develop an extreme (e.g. 90/10) winter forecast in its seasonal assessment.

Generation

The Maritimes Subregion resources will vary between 7,676 MW and 7,686 MW of existing capacity. The Maritimes Subregion does not consider *Conceptual*, future or inoperable resources when doing its seasonal assessment.

During this time period there will be 158 MW of existing wind with a nameplate rating of 775.28 MW.

Wind projected capacity is derated to its demonstrated average output for each winter or winter capability period. In New Brunswick, Prince Edward Island and NMISA the wind facilities that have been in production over an extended period of time a derated monthly average is calculated using metering data from previous years over each seasonal assessment period. Nova Scotia has decided not to include any wind facilities towards their installed capacity (100 percent derated). For those that have not been in service that length of time, the deration of wind capacity in the Maritimes Subregion is based upon results from the Sept. 21, 2005 NBSO report "Maritimes Wind Integration Study".[135] Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Subregion receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. Wind is the only variable resource currently considered in the Maritimes Subregion resource adequacy assessment.

[134] The energy efficiency programs for each area are : www.maritimeelectric.com , www.nppower.com , www.mainepublicservice.com , www.emec.com , www.nspower.ca/energy_efficiency/programs/.

[135] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf.

During this time period there is 150 MW of existing Biomass with a nameplate rating of 155 MW.

The Maritimes Subregion is forecasting normal hydro conditions for the Winter 2011/2012 assessment period. The Maritimes Subregion hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units or providing operating reserve.

The Maritimes Subregion does not expect to experience any conditions that would cause any capacity reductions.

The Point Lepreau generation station will be out of service during the whole Winter Assessment period. With firm purchases from outside the Maritimes Subregion in place, and all scheduled maintenance completed prior to the winter period, there are no anticipated shortfalls in capacity.

Capacity Transactions

There are firm capacity agreements in place between New Brunswick - H.Q. The Firm Capacity purchases have dedicated firm transmission reservations.

There is a firm sale of 207 MW to Hydro- Québec, which is tied to specific generators within New Brunswick (Table 43).

Table 43: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	166
	Expected	-
	Non-Firm	-
	Total	**166**
Exports	Firm	207
	Expected	-
	Non-Firm	-
	Total	**207**
Net Transactions		**(41)**

The Maritimes Subregion does have agreements in place for the purchase of emergency energy with other sub regions as well as a reserve sharing agreement within NPCC. But the Maritimes Subregion does not rely on this assistance when doing its winter assessment.

Transmission

There has been no significant new bulk power transmission addition since the last reporting winter period.

There are no major transmission facilities scheduled to be out of service for extended periods during the 2011/2012 winter with all existing significant transmission line expected to be in service during the winter reporting period. There are no transmission constraints that could impact reliability.

Projected 2011/2012 Winter transfer capabilities include:

- NB to Maine Electric Power Company (MEPCO): 1,000 MW
- MEPCO to NB: 550 MW (presently limited to 450 MW by ISO-NE due to thermal issues but can be increased to 550 MW at the request of the NBSO to prevent shedding of system load due to a capacity deficient event).
- HQ to NB: HVdc + Radial Load = Between 985 MW and 1,019 MW. (The reason for the range is due to the varying radial load during the winter reporting period).
- NB to HQ: 770 MW

The current interregional transmission transfer capabilities are derived from the IPL/NRI (Northeast Reliability Interconnect/International Power Line transmission project) studies of the NB / ISO-NE interface. The import capabilities for the Maritimes Subregion are based on real time values based on transmission and generation being in/out of service. NBSO has rules based on study results for simultaneous transfer capability with our interconnections. Transmission or generation constraints are recognized that are external to the Maritimes Subregion.

Operational Issues

The Maritimes Subregion assesses its seasonal resource adequacy in accordance with NPCC Directory 1 Design and Operation of the BPS (Appendix F).[136] As such, the assessment considers the regional Operating Reserve criteria; 100 percent of the largest single contingency and 50 percent of the second largest contingency. When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritimes Subregion is projecting adequate surplus capacity margins above its operating reserve requirements for the Winter 2011/2012 assessment period.

The amount of wind presently operating does not require any special operational changes.

The Maritimes Subregion is a winter peaking system, minimum demand and over generation will not be a concern. There are adequate generation facilities within the Maritimes that can be removed from or remain out of service to prevent that from happening.

The only demand response considered in this resource adequacy assessment for the Maritimes Subregion is interruptible load. The Maritimes Subregion uses a 20 percent reserve criterion for planning purposes, equal to 20 percent multiplied by (Forecast Peak Load MW – Interruptible Load MW).

There are no environmental or regulatory restrictions which could impact reliability in the Maritimes Subregion during the assessment period and no unusual operating conditions are anticipated for the winter that will impact reliability in the Maritimes Subregion.

[136] https://www.npcc.org/Standards/Directories/Directory%201%20%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20Full%20Member%20Approval%20December%2001,%202009%20GJD.pdf.

Reliability Assessment

When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritimes Subregion is projecting more than adequate surplus capacity margins for the Winter 2011/2012 assessment period.

The projected Reserve Margin for winter 2011/2012 period is 20.7 percent to 25.7 percent as compared to the projected Reserve Margin for the winter 2010/2011 of 20 percent to 32.4 percent.

The Maritimes Subregion does not consider potential fuel-supply interruptions in the regional assessment. The present fuel supply in the Maritimes Subregion is very diverse and it includes natural gas, diesel, coal, petcoke, oil (both light and residual), hydro, tidal, municipal waste, wind and wood.

The New Brunswick portion of the Maritimes transmission system is robust, comprised of a 345 kV transmission ring with additional supporting 230 kV transmissions. For those areas that may suffer low voltage post contingency, there are specific “must run” procedures that require generation online to meet necessary reactive reserves for contingencies. This requirement is applied for generation assessments as well as the day-ahead review to ensure that there are sufficient reactive reserves.

Assessment Area Description

The Maritimes Subregion is a winter peaking system. This area covers approximately 57,800 square miles serving 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). In the Maritimes Subregion, New Brunswick and Nova Scotia are Balancing Authorities. The New Brunswick System Operator is the Reliability Coordinator for the Maritimes Subregion.

NPCC–New England

Executive Summary

ISO New England Inc. (ISO-NE) is the Regional Transmission Organization (RTO) for the six-state New England region and is responsible for the reliable operation of the bulk power system, administration of the region's wholesale electricity markets, and management of its comprehensive planning process. ISO-NE reports that due to the lingering effects of the recession, this year's forecast for winter peak demand remains about the same as last year's forecast. The forecast for this year's winter peak demand is 22,255 MW, which is slightly higher (170 MW) than last winter's forecast demand of 22,085 MW. The *Existing-Capacity* totals 36,980 MW, which includes 30,030 MW of *Existing-Certain* and 5,085 MW of *Existing-Other* capacity. Approximately 904 MW of capacity was added since last year's winter assessment.

For the winter period, *Future Capacity Additions* total 9 MW, which included 0 MW of *Future-Planned* and 9 MW of *Future-Other* capacity additions. All of the capacity additions are wind. The region has no specific or fixed Reserve Margin requirements. The Reserve Margin entitled *Existing-Certain Capacity & Net Firm Transactions* reflects 10,044 MW (45 percent) for the reference case demand forecast and 9,364 MW (41 percent) for the extreme case demand forecast.[137] The Reserve Margin entitled *Anticipated Capacity Resources* also reflects 10,044 MW (45 percent) for the reference case demand forecast. For a fossil-based power system like New England, the NERC Reference Reserve Margin Level is 15 percent.[138] Comparing the Reserve Margin level entitled *Existing-Certain Capacity & Net Firm Transactions* to the NERC Reference Reserve Margin Level results in a 30 percent difference. ISO-NE expects to reliably serve the winter peak and energy demands.

Since the prior winter of 2010/2011, there was one (1) 115 kV line installed between the King Street and West Amesbury Substations in Massachusetts and a second 345/115 kV autotransformer installed at Kent County Substation, located in Rhode Island.

There are three (3) new 345/115 kV autotransformers projected to be installed for this winter period – one each at the Deerfield Substation in New Hampshire, Wachusett Substation in Massachusetts, and Berry Substation in Rhode Island. In addition, there are two (2) new 115 kV capacitor banks at the West Rutland Substation and one (1) 345 kV variable reactor at the Coolidge Substation in Vermont, which are all projected to be placed in-service during the winter timeframe.

During the winter, there are no projections of any significant transmission lines being out-of-service and no transmission constraints are anticipated that would significantly impact regional reliability.
As noted earlier, the New England region is projecting positive Reserve Margins for the winter period. There are no fuel supply concerns, beyond those issues regarding the availability of natural gas supplies

137 This is due to the fact that New England's resource adequacy criterion is based on the 1 day in 10 years Loss of Load Expectation (LOLE).

138 As defined in the NERC Reliability Assessment Guidebook, found at: http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf.

under extreme cold weather conditions, environmental restrictions, transmission constraints, or other operational issues projected for this winter.

Introduction

ISO-NE is the Regional Transmission Organization (RTO) serving the six-state New England region. New England is one of five subregions of the Northeast Power Coordinating Council, Inc. (NPCC).[139] This winter reliability assessment is a deterministic self-assessment, developed by ISO-NE for submittal to the NERC Reliability Assessment Subcommittee (RAS) for peer review.[140]

Demand

Within the NPCC, ISO-NE is the Balancing Authority for the New England subregion and it reports only one (1) subregional electrical peak demand value for the entire Balancing Area. The reference demand forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a dry bulb temperature of 7^{o} degrees Fahrenheit (F).[141] The reference demand forecast is also based on the reference economic forecast, which reflects the regional economic conditions that would “most likely” occur. The reference case winter peak demand forecast is 22,255 MW, which is 170 MW (0.77 percent) greater than last winter’s reference case forecast of 22,085 MW.[142] The key factors driving these somewhat similar forecasts are the continued penetration of energy efficiency and the lingering effects of the economic recession. Prior to weather normalization, ISO-NE’s actual metered 2010/2011 winter peak demand occurred on January 24, 2011 and was 21,060 MW (Table 44).[143] This peak demand occurred at hour ending 19:00 at a temperature of 8^{o} (F) and a -15^{o} dew point.

Table 44: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**22,255**	**January-2012**
2010/2011 Forecast	22,085	January-2011
2010/2011 Actual	21,060	January-2011
All-Time Peak	22,818	January-2004

ISO-NE develops an independent load forecast for the Balancing Area. ISO-NE uses historical hourly demand data from individual member utilities, which is based upon revenue-quality metering. This data is then used to develop historical demand data on which the regional peak demand and energy forecasts are based. From this, ISO-NE develops a forecast of both state and monthly peak and energy demands. The peak demand forecast for the region and the states can be considered a coincident peak demand forecast.

[139] The five NPCC subregions include: Maritimes (New Brunswick and Nova Scotia), New England, New York, Ontario, and Québec.

[140] The winter period includes the three months of December 2011, January 2012, and February 2012.

[141] The 7^{o} (F) is the 95th percentile of a weekly weather distribution and is consistent with the median of the dry-bulb value at the time of the winter peak over the last 30 years.

[142] This value is the same for the *Unrestricted Non-Coincident Peak Demand* (Line 1) and the *Total Internal Demand* (Line 2) from the corresponding NERC 2011/2012 Winter Assessment Spreadsheet, January 2012 values.

[143] The reconstituted (for load reducing actions of FCM Demand Resources) peak demand of 21,616 MW occurred on January 24, 2011 at hour ending 19:00.

ISO-NE plans its system to meet the NPCC's Resource Adequacy Reliability Criterion by using the 50/50 economic reference case demand forecast, which has a 50 percent chance of being exceeded.[144] ISO-NE also bases its winter resource capacity ratings on capability demonstrations by both supply and demand–side resources. ISO-NE subsequently conducts Claimed Capability Audits for the purpose of establishing or verifying these seasonal claimed capability ratings for all resources. These capability demonstrations, which must occur during the winter capability demonstration period, encompass the timeframe from November 1st through April 15th. In addition, internal combustion technologies and both simple/combined cycle units are subsequently rated under ambient air conditions at 20°F.

For this winter, there are 1,864 MW of demand resources which are considered capacity resources within the Forward Capacity Market (FCM). Within this total are 1,104 MW of active demand resources and 760 MW of passive demand resources or Energy Efficiency (Table 45). The relationship between Demand Response programs to a forecast Total Internal Demand of 22,255 MW is approximately 8 percent. An ISO-NE approved Measurement & Verification (M&V) Plan is used for both Demand Response and Energy Efficiency performance evaluation. Commercial operation and seasonal audits are routinely conducted, consistent with ISO-NE Operating Manuals, to ensure that all FCM Demand Resources and Energy Efficiency projects are capable of delivering their contractual demand reductions.

Table 45: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**760**
Non-Controllable Demand-Side Management	
Direct Control Load Management	-
Contractually Interruptible (Curtailable)	-
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	1,104
Total Dispatchanle, Controllable Demand Response	**1,104**
Total Demand-Side Management	**1,864**

ISO-NE addresses peak demand uncertainty in two ways:

- **Weather** – Peak demand distribution forecasts are made based on 40 years of historical weather, which includes the reference case forecast (50 percent chance of being exceeded) and extreme case forecast (10 percent chance of being exceeded).
- **Economics** – Alternative forecasts are made using high and low economic scenarios.

The national and regional recession embodied in the economic forecast used in the development of the 2011 demand forecast is similar to the previous year's demand forecast, and subsequently, the 2011 demand forecast remains only slightly increased. However, no changes have been made to the method for forecasting (summer or winter) demand due to the recession.

[144] ISO-NE bases its capacity requirements on a probabilistic loss-of-load-expectation analysis that calculates the total amount of installed capacity needed to meet the NPCC's once-in-ten-year requirement for preventing the disconnection of firm load due to a capacity deficiency. This value is known as the Installed Capacity Requirement (ICR).

ISO-NE also projects the extreme 90/10 winter peak demand forecast based on the same economic forecast. The extreme case winter peak demand forecast is 22,935 MW, which is 170 MW (0.74 percent) greater than last winter's extreme case forecast of 22,765 MW.

Generation

During the winter peak demand period, ISO-NE has identified approximately 30,030 MW of *Existing-Certain* generating capacity, which is based on winter ratings. Approximately 4,776 MW has been identified within the *Existing-Other* category, which consists of various categories of additional capacity. One category consists of the amount of capacity exceeding 1,400 MW, for those units/stations that exceed the 1,400 MW level as a "single loss-of-source contingency." In real time operations, New England may be required to limit its largest, single loss-of-source contingency to 1,400 MW in order to respect operating agreements with PJM and NYISO. The amount of capacity identified within this first category is approximately 62 MW. Another category of capacity is the amount of nameplate capacity that exceeds the FCM Capacity Supply Obligation (CSO), which is approximately 3,817 MW.[145] The *Existing-Inoperable* category identifies 0 MW of capacity.

There are 9 MW of *Future Capacity Additions* projected for the winter peak demand period. This includes 0 MW of *Future-Planned* and 9 MW of *Future-Other* capacity, which is all wind capacity.

Approximately 55 MW of the *Existing-Certain* capacity is wind generation that is projected to be available at the time of peak demand. This reflects a 63 MW derate on-peak, from the total wind nameplate capability of 119 MW. There is no solar generation within the *Existing-Certain* capacity category. ISO-NE's wind capacity is rated seasonally. Wind capacity during the summer and winter seasons is equal to the average of a median calculation performed for each year over the previous five years. For the winter season, the median calculation is the median capacity (MW output) during the hours ending 18:00 through 19:00, each day of October through May and any winter hour with a "shortage event".[146,147]

Biomass capacity within the *Existing-Certain* category totals 911 MW.

The *Existing-Certain* capacity also includes 1,490 MW of hydro-electric resources. This reflects a 402 MW derate on-peak, from the total hydro-electric nameplate capability of 1,892 MW (Table 46). Monthly ratings for hydro-electric resources with little or no storage capability are calculated based on the maximum capacity of the unit(s), adjusted for historical, seasonal hydrological conditions and upstream storage. Those hydro-electric units with pondage and storage of at least ten times their seasonal claimed capability rating must annually demonstrate their summer and winter capacity. The National

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[145] The CSO is the FCM contracted capacity, which would receive payments for reliably serving the 2011 summer and 2011/2012 winter peak and energy demands.

[146] For the summer season, the median calculation is the median capacity (MW output) during the hours ending 14:00 through 18:00, each day of June through September and any summer hour with a "shortage event."

[147] These are events under which ISO-NE Operations is currently experiencing either a shortage of operating reserves or a capacity deficiency.

Oceanic and Atmospheric Administration (NOAA) projects the hydrological conditions for New England for this winter should be in between the current neutral El Niño Southern Oscillation (ENSO) pattern to a mild La Niña pattern.[148] This should result in variable temperatures and average precipitation for the region.

Table 46: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	55
	Derated	63
	Wind - Total Nameplate Capacity	**119**
Solar	Expected	-
	Derated	-
	Solar - Total Nameplate Capacity	**-**
Hydro	Expected	1,490
	Derated	402
	Hydro - Total Nameplate Capacity	**1,892**
Biomass	Expected	911
	Derated	83
	Biomass - Total Nameplate Capacity	**994**

ISO-NE is not projecting any disruptions to regional fuel supply chains serving New England's electric power sector. Approximately 900 of capacity is projected to be out of service on maintenance during the January 2012 winter peak demand period. This amount of capacity has been accounted for within the Reserve Margin calculations.

Capacity Transactions

The winter *Capacity Imports* amount to 505 MW, which includes 296 MW from Québec and 209 MW from New York (Table 47). Only *Capacity Imports* that have been qualified and contracted for delivery within the 2011/2012 FCM Capability Commitment Period are defined as *Firm Capacity Imports*.[149] These *Firm Capacity Import* contracts rely on external resources to satisfy their FCM Capacity Supply Obligation (CSO), which in turn, contributes to meeting the region's overall Installed Capacity Requirement (ICR).

Table 47: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	505
	Expected	-
	Non-Firm	-
	Total	**505**
Exports	Firm	100
	Expected	-
	Non-Firm	-
	Total	**100**
	Net Transactions	**405**

148 NOAA's website is located at: http://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=3

149 The 2011/2012 FCM Capability Commitment Period is from June 1, 2011 to May 31, 2012.

While the entire 505 MW of *Firm Capacity Imports* are backed by FCM "qualified" contracts, there is no requirement for those *Firm Capacity Imports* to have firm transmission service. Under FCM rules, the deliverability of external capacity imports must meet the same delivery requirements as those of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of energy associated with these *Capacity Imports*, but that market participant also bears the associated risks of FCM non-delivery penalties if it chooses to use non-firm transmission. There are no *Capacity Import* contracts that can be characterized as "liquidated damage contracts" or "make-whole" contracts as defined by FERC Order 890.

The winter *Capacity Exports* amount to 100 MW, which is to New York (Long Island) via the Cross-Sound Cable. Only *Capacity Exports* that have been qualified and contracted for export within the 2011/2012 FCM Capability Commitment Period are defined as *Firm Capacity Exports*.

Although *Capacity Exports* are backed by firm generation contracts, FCM rules dictate that this type of capacity and associated energy can only be recallable by ISO-NE in an extreme emergency situation, i.e., just prior to implementation of internal load shedding actions. There are no *Capacity Export* contracts that can be characterized as "liquidated damage contracts" or "make-whole" contracts as defined by FERC Order 890.

ISO-NE bases its annual capacity requirement on a probabilistic loss-of-load-expectation analysis that calculates the total amount of Installed Capacity Required (ICR) to meet the NPCC's once-in-ten-year requirement for preventing the disconnection of firm load due to a capacity deficiency. Within ISO-NE's calculation of its ICR, emergency imports are characterized as "tie benefits." The combined amount of tie benefits from the three external NPCC subregions is 1,800 MW, which are sub-categorized as 911 MW from Québec, 173 MW from New York and 716 MW from the Maritimes.

Transmission

Within the New England Balancing Authority area, the following new bulk power transmission facilities have been placed in-service since last winter:

- In April 2011, a new 115 kV line was installed between the King Street and West Amesbury Substations in northeastern Massachusetts. This is part of the Merrimack Valley-North Shore Project that addresses various thermal and voltage issues in northeast Massachusetts.
- In early 2011, the expansion of the Kent County 345/115 kV substation was completed in Rhode Island. The expansion included installing a second 345/115 kV autotransformer as part of the Greater Rhode Island Transmission Reinforcements Project. These expansions provide additional transformation in the area to address various thermal and voltage issues.

Within the New England Balancing Authority area, the following new bulk power transmission facilities are projected to be placed in-service this winter:

- In New Hampshire, a second 345/115 kV autotransformer at the Deerfield Substation.
- In central Massachusetts, a third 345/115 kV autotransformer at the Wachusett Substation. This is part of the Central/Western Massachusetts Upgrade Project.

- In Rhode Island, a new substation, named Berry, with one (1) 345/115 kV autotransformer. This is part of the Greater Rhode Island Transmission Reinforcements project.

No additional substation equipment such as SVC, FACTS controllers or HVdc have been added since the prior winter season. For the winter period, there are three (3) reactive devices projected to be placed in-service within Vermont – two (2) 115 kV 25 MVAr capacitor banks at the West Rutland Substation and one (1) 345 kV 60 MVAr variable reactor at the Coolidge Substation.

There are no reliability concerns in not meeting the in-service date for the aforementioned facilities and there is no specific transmission additions deemed necessary to meet the demand forecast for this winter.

ISO-NE does not expect any major transmission lines or facilities to be out-of-service during the winter. However, if major transmission outages were to occur, system reliability would be maintained during real-time operations through adherence to ISO-NE Operating Procedure No. 19 - *Transmission Operations* (OP-19) criteria.[150]

During the winter, no significant transmission constraints are anticipated that would significantly impact regional reliability. However, under certain operating conditions, there are localized system requirements that are dependent upon the operation of local area generation. Operating procedures and guides are in place to address temporary outages of this type of "must-run" generation. Where system upgrades are required for a long-term solution, they are listed within the ISO-NE Regional System Plan (RSP) Project List.[151]

The nominal interregional transmission transfer capabilities are summarized below (Table 48). These interregional transfer capabilities are also reviewed and (re)calculated on a day-to-day basis within real-time. All of the studies recognize both transmission and generation constraints within New England and within external power systems.

[150] http://www.iso-ne.com/rules_proceds/operating/isone/op19/index.html

151 The tri-annual publication of the ISO-NE RSP Project List is located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html

Table 48: New England's Interregional Transmission Capabilities (MW)[152,153]

Transmission Interface	Transfer Capability (MW)	Reference
New Brunswick - New England	1,000	Second New Brunswick Tie Study
Hydro-Québec - New England Phase II	1,400	PJM and NYISO Loss of Source Studies
Hydro-Québec - Highgate	200	Various Transmission Studies
New York - New England	1,600	NYISO Operating Study, Winter 2009/2010
Cross-Sound Cable	330-346	Cross-Sound Cable System Impact Study

Operational Issues

There are no significant anticipated unit outages, environmental restrictions, variable resources, transmission constraints or temporary operating measures that would adversely impact system reliability during the winter. ISO-NE's existing operating procedures should be effective in handling any issues associated with the upcoming winter season.

During extremely cold winter days, there may be fuel supply restrictions on natural gas-fired generating units, due to regional gas pipelines invoking delivery prioritization amongst their entitlement holders. Such conditions routinely occur, resulting in temporary reductions in gas-fired capacity. These temporary reductions to operable capacity are reflected within ISO-NE's forced outage assumptions. ISO-NE monitors these potential situations and mitigates their effects by dispatching non-gas-fired resources to replenish these temporary forced outages.

To date, there are no special operating procedures that are a result of the recent integration of variable or intermittent resources such as wind or solar. Since ISO-NE has only about 1 MW of solar capacity within its system, there is no current need to forecast the output of solar resources.

There are no concerns resulting from a minimum demand/over generation scenario. ISO-NE currently has Market Rules, Manuals, and System Operating Procedures (SOPs) in place to mitigate this type of scenario during anytime of the year.[154,155,156]

The implementation of the new Forward Capacity market has enhanced the integration of demand resources into the operation of the system. Operating Procedures have been developed or revised to dispatch these demand resources. In addition, enhancements to the study tools used by the System

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152 The Hydro-Québec Phase I/II Interconnection is a DC tie with equipment ratings of 2,000 MW. Due to the need to protect for the loss of this line at full import level in the PJM and NY Control Areas' systems, ISO-NE has assumed its transfer capability for capacity and reliability calculation purposes to be 1,400 MW. This assumption is based on the results of loss of source analyses conducted by PJM and NYISO.

153 The capability of the Cross-Sound Cable is 346 MW. However, losses reduce the amount of capacity that is actually delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal. Recent study work has confirmed that the transfer capability from New York (Long Island) to New England (Connecticut) is very dependent on the specific generation dispatch at New Haven and it could be reduced to zero when the New Haven Harbor units are operating at fully rated capacity.

154 ISO-NE Market Rule 1 – Section III.2.5(c).

155 ISO-NE Manual 11, Market Operations, Section 2.5.12: Emergency Conditions in the Day-Ahead Energy Market, Subsection 2.5.12.2: Minimum Generation Conditions, and, Section 2.5.13: Emergency Conditions in the Real-Time Energy Market, Subsection 2.5.13.2: Minimum Generation Conditions.

156 ISO-NE System Operating Procedure SOP-RTMKTS.0120.0015 - Implement Minimum Generation Emergency Remedial Action.

Operators to anticipate system impacts as a result of the demand reductions are also in place. Beginning on June 1, 2011, System Operators are now able to dispatch demand resources to a greater level of geographic granularity, by increasing the number of dispatch zones/regions within New England, from 8 to 19. This now allows the System Operators to dispatch these demand-side resources where and when they are needed, and in an amount similar to that of a traditional generator dispatch.

There are no environmental or regulatory restrictions currently being discussed or forecast for the region that may impact system reliability. There are no unusual operating issues or concerns that are anticipated which may impact the reliable operation of the New England transmission system during the winter.

Reliability Assessment Analysis

ISO-NE bases its capacity requirements on a probabilistic loss-of-load-expectation analysis that calculates the total amount of installed capacity needed to meet the NPCC's once-in-ten-year requirement for preventing the disconnection of firm load due to a capacity deficiency. This value, known as the Installed Capacity Requirement (ICR), was calculated to be 32,463 MW for the 2011/2012 Capability Commitment Period.[157] After subtracting the Hydro-Quebec Interconnection Capability Credits (HQICCs at 911 MW), the net amount of capacity needed to meet the resource adequacy criterion is 31,552 MW. ISO-NE's latest resource adequacy information for this winter is detailed in ISO-NE's December 1, 2010 FERC Filing entitled *"Filings of ISO New England Inc. and New England Power Pool, Filing of Installed Capacity Requirements, Hydro Quebec Interconnection Capability Credits and Related Values for 2011/2012 and 2012/2013 Annual Reconfiguration Auctions", Docket No. ER11-2281-000."*

The *Existing-Certain* and Anticipated Capacity Resources each total 32,299 MW. The projected Existing and Anticipated winter Reserve Margins are 10,044 MW, which equates to approximately 45 percent. The Prospective Capacity Resources totals 32,308 MW. The projected Prospective winter Reserve Margin is 10,053 MW, which equates to approximately 45 percent.

ISO-NE bases its capacity requirements on a probabilistic loss-of-load-expectation analysis that calculates the total amount of installed capacity needed to meet the NPCC's once-in-ten-years requirement for preventing the disconnection of firm load due to a capacity deficiency. This has resulted in a reserve capacity requirement of 3,892 MW, or 14.1 percent of the forecast 50/50 annual peak, for the upcoming winter. However, there are no fixed or predefined Regional, subregional, state, or provincial requirements, targets or guidelines for Reserve Margins as a percent of peak load (summer or winter).

[157] The 32,463 MW Installed Capacity Requirement (ICR) value reflects the amount of capacity needed year round to meet the ISO New England resource adequacy planning criterion of disconnecting non-interruptible customers once in 10 years. It also reflects the reliability benefits of the HQ Phase I/II HVdc Transmission Facilities (HQ Phase II tie) at 911 MW. The net amount of capacity needed for the 2011/2012 capability period, after accounting for the reliability benefits of the HQ Phase II tie, is 31,552 MW.

This year's and last year's projected winter Reserve Margins are summarized in Table 44. For the previous winter peak demand period, the projected Reserve Margin under the reference case peak demand forecast was approximately 9,927 MW (45 percent), and the Reserve Margin under the extreme case peak demand forecast was approximately 9,247 MW (41 percent). Both the reference and extreme demand case Reserve Margin forecast for this winter are 117 MW higher than the reference and extreme demand case Reserve Margin forecast for last winter.

In addition to discussing the winter outlook with regional stakeholders, ISO-NE has also attended several regional fuel supply conferences and seminars, and is pleased to report that no fuel supply or deliverability concerns have been identified for this winter.[158] Historically, concerns over access to and delivery of natural gas to the regional power generation sector have been an ongoing issue within New England during the winter months.

ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability. Because natural gas is the predominant fuel used to produce electricity in New England, ISO-NE continuously monitors the regional natural gas pipeline systems, via their Electronic Bulletin Board (EBB) postings, to ensure that emerging gas supply or delivery issues can be incorporated into and mitigated within the daily or next-day operating plans. Should natural gas issues arise, ISO-NE has predefined communication protocols in place with the Gas Control Centers of both regional pipelines and local gas distribution companies (LDCs), in order to quickly understand the emerging situation and subsequently implement mitigation measures. ISO-NE has two procedures that can also be invoked to mitigate regional fuel supply emergencies impacting the power generation sector:

1. ISO-NE's Operating Procedure No. 21 - *Action during an Energy Emergency (OP21)* is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel supply deficiencies that can occur anytime during the year.[159] Fuel supply deficiencies are the temporary or prolonged disruption to regional fuel supply chains for coal, natural gas, LNG, and heavy and light fuel oil.
2. ISO-NE's Market Rule No. 1 – Appendix H – *Operations during Cold Weather Conditions* is a procedure that is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to the combined effects from extreme cold winter weather or constraints with regional natural gas/LNG supplies or deliveries.[160]

For this winter, transmission planning studies have demonstrated that adequate reactive resources are provided throughout New England. In instances where dynamic reactive power supplies are needed, devices such as static synchronous compensators (STATCOMs), static VAR compensators (SVCs), synchronous condensers, and Dynamic Volt-Ampere-Reactive systems (DVARs) have been employed. If additional reactive power support is necessary in real-time, generation would be committed to meet

[158] The Northeast Energy and Commerce Associations' (NECA) 17th Annual Fuels Conference held on September 27, 2011 as well as through routine interaction with regional stakeholders on the Electric/Gas Operations Committee.

[159] Operating Procedure No. 21 is located on the ISO's web site at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.

160 Appendix H of Market Rule No. 1 is located at: http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-h.pdf.

that requirement. Operational dynamic studies are performed in the near-term to develop and update operating guides supporting adequate voltage/reactive performance.

Other Area-Specific Issues

The ongoing reliability concern for this winter involves the reliability implications to the electric power system resulting from very-extreme winter weather or a force majeure event on the regional natural gas system. As noted by the events that occurred in the southwest during February of 2011, extreme winter weather has the capability to impact the availability of generation by inducing cold-weather related outages.[161] Although the majority of New England's generation fleet took various remedial actions to "cold-weather-proof" their stations after the Cold Snap of January 2004, portions of the fleet may still be susceptible to outages induced by extreme winter weather. [162,163] In addition, an extreme contingency located upstream or on the regional natural gas grid, although temporary in nature, could create regional gas supply shortages, which in turn, would primarily affect the regional gas-fired generation fleet due to their subordinate entitlements for both supply and transportation. Either type event could quickly diminish the Reserve Margins projected for the winter, which would require ISO-NE to implement Emergency Operating Procedures (EOPs) to mitigate the impacts from these events. There are no other region-specific issues that were not mentioned above.

Assessment Area Description

ISO New England Inc. is a Regional Transmission Organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It is responsible for the reliable operation of New England's bulk power generation and transmission system, administering the region's wholesale electricity markets, and managing the comprehensive planning of the regional bulk power system. The New England electric power system serves 14 million people living in a 68,000 square-mile area. New England is a summer-peaking electrical system, which recorded its all-time peak demand of 28,130 MW on August 2, 2006.

161 The full report entitled *"Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011"* is available on the NERC website located at: http://www.nerc.com/.

162 'Cold weather-proofing' or 'winter weatherization measures' include various activities such as installing temporary heaters, wind breaks, insulation, and/or heat trace.

163 Reference various ISO-NE reports on the Cold Snap of January 2004 located at: http://www.iso-ne.com/pubs/spcl_rpts/2004/index.html.

NPCC–NYISO

Executive Summary

The New York Balancing Authority 2011/2012 winter peak load forecast is 24,533 MW, which is 244 MW higher than the 24,289 MW forecast peak for the 2010/2011 winter and 121 MW less than the actual winter peak in 2010/2011 of 24,654 MW. This forecast load is 3.95 percent lower than the all-time winter peak load of 25,541 MW that occurred on December 20, 2004. *Existing-Certain* Capacity in the New York Control Area (NYCA) for the upcoming winter operating period is expected to be 34,142 MW. 627 MW of Certain Capacity has been added since winter 2010/2011. There are 17 MW of capacity expected to be added during this period, which largely consists of new wind farms. With the existing certain capacity of 34,142 MW and the expected peak of 24,533 MW, there is a Reserve Margin of 46.8 percent for the 2011/2012 winter season. This exceeds the 15.5 percent annual Reserve Margin set by the New York State Reliability Council.

Four significant transmission modifications have occurred since the 2010/2011 winter operating period. The Consolidated Edison M29 project consists of a circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, then to two three-winding 345/138/13.8 transformers and two 138 kV PAR controlled transformers into Sherman Creek 138 kV. The Luther Forest Project is National Grid's transmission reinforcement project for their 115 kV transmission system between Rotterdam Substation and Spier Falls Substation.[164] The NYSEG/RG&E Stony Ridge Project includes a new Stony Ridge 230 kV substation, which is located on the Canandaigua-Hillside 230 kV line, and a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation. Lastly, a new 138 kV circuit from Ramapo to Sugarloaf, L28, will be in service in December.

The NYISO expects no outstanding challenge aside from the typical challenges in operating the Bulk Power System.

Introduction

NYISO is the only Balancing Authority in the New York Control Area. The NYCA is over 48,000 square miles serving a total population of about 19.4 million people and peaks annually in the summer. This report addresses the reliability assessment for the NYCA for December 2011 through February 2012.

Demand

The 2011/2012 winter forecast assumes normal weather conditions for both energy usage and peak demand. The economic outlook is derived from the New York forecast provided to the NYISO by Moody's Economy.com. Econometric models are used to obtain energy forecasts for each of the eleven zones in New York. A winter load factor is used to derive the winter peak from the annual energy forecast.

The New York Balancing Authority 2011/2012 winter peak load forecast is 24,533 MW, which is 244 MW higher than the forecast of 24,289 MW peak for the 2010/2011 winter and 121 MW less than the actual

[164] The project is located in Saratoga County, New York in the Saratoga/Glens Falls area.

winter peak in 2010/2011 of 24,654 MW (Table 49). This forecast load is 3.95 percent lower than the all-time winter peak load of 25,541 MW that occurred on December 20, 2004.

Table 49: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**24,533**	**January-2012**
2010/2011 Forecast	24,289	January-2011
2010/2011 Actual	24,654	December-2010
All-Time Peak	25,541	December-2004

The NYISO conducts a load forecast uncertainty analysis based on the combined effects of the weather and the economy. This analysis is conducted for annual energy, summer peak demand and winter peak demand. The results of this analysis are used to make projections of upper and lower bounds of each of these forecasts.[165] The forecast, does not explicitly address extreme winter conditions.

Peak load forecasts are provided by Consolidated Edison (“ConEd”) for its service territory, and by the Long Island Power Authority for Long Island (“LIPA”). Con-Ed's service territory includes New York City and most of adjacent Westchester County, and is contained within the NYISO Zones H, I and J. The LIPA service territory is contained within the NYISO Zone K. ConEd and LIPA provide the NYISO with both coincident and non-coincident peak demands. The NYISO aggregates the utility forecasts with the remaining Zones A through G that comprise the New York Control Area.

The daily peak demand observed by New York during the Winter Operating Period occurs in the late afternoon to early evening. For daily forecasting purposes, the NYISO uses a weather index that relates dry bulb air temperature and wind speed to the load response in the determination of the forecast. At the peak load conditions, a one-degree decrease in this index will result in approximately 100 MW of additional load. The expected temperature at which the New York load could reach the forecast peak is 12.9°F (-11°C).

The NYISO has two Demand Response programs: the Emergency Demand Response Program (“EDRP”) and ICAP Special Case Resources (“SCR”) program. Both programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid.

The EDRP and SCR programs are designed to reduce power usage through the voluntary shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to take part in the EDRP or to become SCRs. EDRP participants are paid by the NYISO for reducing energy consumption when called upon by the NYISO. SCRs must agree in to curtail power usage on demand and are paid in advance for their commitment.

The NYISO's Day-Ahead Demand Response Program (“DADRP”) allows energy users to bid their load reductions, into the Day-Ahead energy market as generators do. Offers determined to be economic are

[165] The upper bounds are located at the 90th percentile and the lower bounds at the 10th percentile. The forecast method incorporates the impact of the economy on load via the inclusion of macroeconomic variables in the econometric model.

paid at the market clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and moderate prices.

Estimated enrollment of SCR resources for the winter capability period is 1,882 MW and EDRP enrollment is estimated at 166 MW for a total of 2,048 MW (Table 50). Full deployment of the estimated resources may reduce the peak demand of 24,533 MW by up to 8.3 percent.[166]

Table 50: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**2,800**
Non-Controllable Demand-Side Management	
Direct Control Load Management	-
Contractually Interruptible (Curtailable)	-
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	2,048
Total Dispatchanle, Controllable Demand Response	**2,048**
Total Demand-Side Management	**4,848**

The New York State Public Service Commission ("NYSPSC") issued an order in June 2008 directing state organizations to implement its Energy Efficiency Portfolio Standard ("EEPS"). The goal of EEPS is to reduce the projected energy consumption in the year 2015 by 15 percent of forecasted demand levels (approximately 27,500 GWh). The estimated reduction in peak demand, if the full impact of these programs is achieved, would reduce summer peak demand by about 5,600 MW. For the total winter peak, demand reduction is estimated to be about 2,800 MW.

The NYSPSC made provisions for the funding of measurement and verification of the EEPS. The NYISO is a member of the Evaluation Advisory Group, which provides input to the Public Service Commission on methods and standards used to verify the level of savings the EEPS achieves in practice.

The New York State Energy Research and Development Agency ("NYSERDA") also implements state-funded energy efficiency programs as authorized by the Public Service Commission. NYSERDA publishes periodic reports on the measurement and verification of the programs it implements.

The NYISO performs an analysis to determine winter peak loads at extreme weather conditions. These conditions are based on a Monte Carlo simulation that determines winter peak loads at many different temperatures, both above and below design conditions. Design conditions are defined as the 30-year average of temperatures at the time of the winter peak load.

The NYISO has not changed its forecast method in response to the economic recession. Its method is to produce an annual energy forecast using econometric models specific to each of the NYISO's zones. [167]

[166] All SCR and EDRP program participants submit hourly interval data to the NYISO so that actual performance indices may be calculated. The NYISO files bi-annual reports to the FERC regarding the performance of these programs.

Energy efficiency impacts are subtracted from the econometric forecasts to obtain the base forecast for the NYISO.

The economic assumptions used in the NYISO's forecast are updated two to four times per year. The most recently available economic forecast is used to develop the NYISO's long term forecast each year.

The 5-year average growth rate in winter peak demand has been decreasing as a result of the recession. In 2008, the average annual growth rate was 1.15 percent; in 2009 it was 0.48 percent, in 2010 it was 0.77 percent; in 2011 it was 0.66 percent. The 2011/2012 winter peak forecast in 2008 was 26,128 MW. The current forecast for 2011/2012 is 24,533 MW.[168]

Generation

For 2011/2012 the New York Balancing Area expects 42,881 MW of existing capacity, with 34,142 MW of that classified as *Existing-Certain* and 1,882 MW classified as expected Supply-Side Demand Response. Of the *Existing-Certain* capacity, 393 MW is from wind generation, 262 MW is biomass generation and 5 MW is solar generation. Based on historical performance, a 5.67 percent derate factor is applied for the majority of generators, including biomass. Wind generation is derated to 30 percent of rated capacity, a 70 percent derate factor, in the winter operating period. Solar generation is derated to 16 percent of rated capacity, an 84 percent derate factor, in the winter operating period. For the winter period nameplate additions of 57.4 MW of wind generation (derated to 17.2 MW) are expected to be added, totaling 1,311 MW (Table 51).

Table 51: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	393
	Derated	918
	Wind - Total Nameplate Capacity	**1,311**
Solar	Expected	5
	Derated	27
	Solar - Total Nameplate Capacity	**32**
Hydro	Expected	5,132
	Derated	546
	Hydro - Total Nameplate Capacity	**5,678**
Biomass	Expected	262
	Derated	79
	Biomass - Total Nameplate Capacity	**341**

[167] The winter peak demand for each zone is derived from the energy forecast through the use of a winter load factor. The NYCA peak is the sum of the coincident zonal peaks. Non-coincident zonal winter peak demands are derived from the coincident winter peak demands by a diversity factor, defined as the five year average of the ratio of the non-coincident peak to the coincident peak.

[168] The Monte Carlo simulation described above provides results used to determine peak loads at the 90th percentile and the 10th percentile of design conditions. These forecasts are reported annually in the NYISO's Load and Capacity Data Report.

Hydro-electric conditions are anticipated to be sufficient to meet the expected demand this winter. The New York Control Area is not experiencing continued effects of a drought or any conditions that would create capacity reductions. Reservoir levels are expected to be normal for the upcoming winter. NYISO is not experiencing or expecting conditions that would reduce capacity.

No significant generating units will be out-of-service or retired between December 2011 and February 2012.

Capacity Transactions

The NYISO projects net imports into the New York Balancing Authority area of 965 MW during winter 2011/2012 (Table 52).[169]

Table 52: On-Peak Capacity Transactions

	Transaction Type	Winter 2011/2012 (MW)
Imports	Firm	-
	Expected	965
	Non-Firm	-
	Total	**965**
Exports	Firm	-
	Expected	-
	Non-Firm	-
	Total	**-**
	Net Transactions	**965**

Capacity purchases in New York are not required to have accompanying firm transmission reservations, but adequate transmission rights must be available to assure delivery to New York when scheduled. External capacity is also subject to external availability rights. Availability on the import interface is offered on a first-come first-serve basis. The total capacity purchased for this winter operating period may increase since there remains both time and external rights availability. Liquidated Damage Contracts are not included.[170]

Transmission

Four significant transmission modifications have occurred since the 2010/2011 winter operating period.

- The Consolidated Edison M29 project consists of a circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, then to two three-winding 345/138/13.8 transformers and two 138 kV PAR controlled transformers into Sherman Creek 138 kV.

[169] Due to NYISO market rules the specific projected sales and purchases are considered confidential non-public Confidential Information under the NYISO's Code of Conduct and therefore cannot be provided in this report.

[170] Under the NYISO's Code of Conduct, information on specific import and export transactions is considered Confidential Information. Information on the aggregated or net expected capacity imports and exports during peak winter conditions is not yet known. Capacity is traded in the NYISO market as a monthly product, and total imports and exports are not finalized until shortly before the month begins. NYISO does not rely on external resources for emergency assistance.

- The Luther Forest Project is National Grid's transmission reinforcement project for their 115 kV transmission system between Rotterdam Substation and Spier Falls Substation. The Project will be located in Saratoga County, New York in the Saratoga/Glens Falls area.
- The NYSEG/RG&E Stony Ridge Project includes a new Stony Ridge 230 kV substation, which is located on the Canandaigua-Hillside 230 kV line, and a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation.
- Orange and Rockland has installed a second 138 kV circuit from Ramapo to Sugarloaf, L28, which will be in service in December 2011.

The Watercure 345/230 kV transformer bank, the Norwalk Harbor – Northport 138kV 1385 NNC 601 cable between New England and Long Island, and the South Mahwah-Waldwick 345 kV J3410 line have returned to service since the 2010/2011 winter operating period. The Beck-Packard 230 kV BP76 remains out-of-service for the winter 2011/2012 operating period. The PA-301 will be out-of-service from December 1-16, 2011.

The NYISO does not have any transmission constraints that could significantly impact reliability. New York Balancing Authority area import capability is summarized in the table below (Table 53). These values are derived by joint studies with adjoining regions and recognize transmission and generation constraints.

Table 53: NYISO Transfer Capabilities

Import Area	Transfer Capability (MW)
PJM	3,000
Linden VFT	300
Neptune Cable	660
Québec	1,500
Cedars-Dennison	166
New England	1,300
Cross Sound Cable	340
1385 Cable	200
Ontario	2,250

Operational Issues

The NYISO routinely conducts a winter operating study for the November 1 through April 30 winter capability period. There have been no significant special operating studies performed for the winter 2011/2012 period. NYISO does not have any reliability concerns resulting from minimum demand and over generation due to variable resources. Wind is integrated into the security constrained dispatch (SCD). As a result, wind can be curtailed to address transmission constraints based on their shift factors and economic offers. Wind resources receive base points from the NYISO and financial penalties will be assessed for non-response. Because wind is managed through SCD the need for special operating procedures is limited.

The NYISO does not expect any reliability concerns resulting from its Demand Response Programs.

The 2010 Reliability Need Assessment ("RNA")[171] is a 10-year planning study conducted by the NYISO as part of its Comprehensive System Planning Process. The 2010 RNA identified no Reliability Needs, assuming that all modeled transmission and generation facilities, including Indian Point, remain in service during the next 10 years from 2011 through 2020. The study of the Base Case indicated that the baseline system meets all applicable Reliability Criteria. However pending regulatory initiatives, including proposed more restrictive environmental emission programs, may affect base case facilities and could result in unanticipated retirement of capacity in New York. The NYISO will continue to monitor these developments and will conduct appropriate reliability studies as necessary.

There are no anticipated unusual operating conditions that could significantly impact reliability for the upcoming winter.

Reliability Assessment

With the existing certain capacity of 34,142 MW and the expected peak of 24,533 MW, there is a wintertime Reserve Margin of 46.8 percent. This exceeds the 15.5 percent annual Reserve Margin set by the New York State Reliability Council (NYSRC).

NYISO complies with NPCC and NYSRC resource adequacy criteria of no more than one occurrence of loss of load per ten years due to a resource deficiency, as measured by 0.10 days/year LOLE.[172]

The NYSRC establishes the Installed Reserve Margin ("IRM")[173] based on a technical study conducted by the NYISO and the Installed Capacity Subcommittee (of the NYSRC). The 2011/2012 IRM Study found that the New York Control Area has the required amount of installed capacity needed to meet the 0.1 days/year LOLE criterion. Following this study, the NYISO conducts the Locational Installed Capacity Requirements (LCR) study[174]. This study determines the amount of Unforced Capacity (UCAP) that load serving entities must procure to reliably meet demand in New York's high load Areas.

NYISO has adopted the New York State Gas-Electric Coordination Protocol as Appendix BB[175] to its Open Access Transmission Tariff (OATT). This Coordination Protocol applies to circumstances in which the NYISO has determined (for the bulk power system) or a Transmission Owner has determined (for the local power system) that the loss of a Generator due to a Gas System Event would likely lead to the loss of firm electric load. This Coordination Protocol also applies to communications following the declaration of an Operational Flow Order or an Emergency Energy Alert. There are no anticipated fuel delivery problems for this winter operating period.

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[171] NYISO Report, "2010 Reliability Needs Assessment", September 2010: http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2010_Reliability_Needs_Assessment_Final_09212010.pdf.

[172] The LOLE assumptions take into account demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.

[173] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2011 Through April 2012" (December 10, 2010).

[174] NYISO Report titled "LOCATIONAL MINIMUM INSTALLED CAPACITY REQUIREMENTS STUDY COVERING THE NEW YORK CONTROL AREA For The 2011–2012 Capability Year, May 18, 2011.

[175] New York State Gas-Electric Coordination Protocol, Attachment BB to the NYISO Open Access Tariff (OATT), April 28, 2011.

The NYISO performs dynamic and static reactive power studies based on anticipation of issues. No reactive power issues are anticipated for this winter.

Assessment Area Description

NYISO[176] is the only Balancing Authority in the New York Control Area. The NYCA is covers over 48,000 square miles serving a total population of about 19.4 million people and peaks annually in the summer.

[176] The NYISO Website is: http://www.nyiso.com.

NPCC–Ontario

Executive Summary

The forecast peak for winter 2011/2012 is 22,311 MW which is 1.7 percent lower than last year winter's weather-corrected peak demand of 22,695 MW. The decrease is the result of conservation, growth in embedded generation and time-of-use rates. The total *Existing-Certain* capacity will be 35,107 MW of which 28,575 MW certain capacity is expected to be available at the time of winter peak in January 2012. Since last summer 1,032 MW of *Existing-Certain* capacity was added while 1,890 MW was retired. *Future-Planned* resources amounting to 261 MW will be added through the assessment timeframe and 980 MW of coal generation will be retired by the end of 2011. On average, the anticipated Reserve Margin over the winter period is 36.3 percent which is higher than the Ontario target of 21.8 percent.

Hydro One installed series compensation on the 500 kV north-south lines at Nobel Switching Station to increase the transfer capability. Two new municipal transformer stations (MTS) were added to the transmission network. As far as operability is concerned, Ontario has sufficient operational and market measures in place to meet its winter energy demands.

Introduction

The IESO is the Reliability Coordinator and Balancing Authority for the province of Ontario. The IESO manages the wholesale electricity market and oversees the reliable operation of the provincial electricity grid.

Ontario's resource portfolio and transmission system are adequate to meet the expected demands over the winter 2011/2012. This self-assessment narrative is based on the results from the 18-Month Outlook published in August 2011 on the IESO website.[177] The IESO gathers information relating to generation and transmission resources from Market Participants.

Demand

The IESO is forecasting a winter peak demand of 22,311 MW for Ontario.[178] The forecast peak for winter 2011/2012 is 1.9 percent lower than last winter's actual peak of 22,733 MW, which occurred on January 24, 2011 under near normal conditions (Table 54). The 2011/2012 winter peak forecast is 1.7 percent lower than last winter's weather-corrected actual peak demand of 22,695 MW. The 2011/2012 winter peak forecast is 0.1 percent lower than last winter's forecasted peak demand of 22,474 MW. The current forecast's decrease is the result of several factors – conservation initiatives, growth in embedded generation and price incentives to modify consumption patterns during peak periods.

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[177] http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2011aug.pdf.

[178] This forecast is based on Monthly Normal weather and incorporates the impacts of planned conservation, growth in embedded generation, time-of-use rates and weak economic climate.

Table 54: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**22,311**	**January-2012**
2010/2011 Forecast		
2010/2011 Actual	22,733	January-2011
All-Time Peak	24,979	December-2004

Since the Ontario forecast is at the system level, it represents the coincident peak of the zones that make up the IESO-controlled grid. The peak conditions are generated using Monthly Normal weather. This provides a typical monthly peak for each of the winter months based on 31 years of weather data history.

A number of loads within the province participate in demand response programs with a total capacity greater than 1,900 MW or 8.7 percent of forecasted peak demand (Table 55). Of this total capacity about 1,200 MW is included for seasonal capacity planning purposes, of which 775 MW is deemed to be interruptible. The IESO dispatches and settles the majority of the demand response capacity and the measurement and verification is done within the settlement process. The remaining capacity is verified and measured by the Ontario Power Authority (OPA) which has responsibility for those remaining programs. Additionally, 249 MW of Energy Efficiency programs will provide additional Demand-Sided Management (DSM).

Table 55: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)	Percent of Peak Demand (%)
Energy Efficiency (New Programs)	**249**	
Non-Controllable Demand-Side Management		
Direct Control Load Management	-	
Contractually Interruptible (Curtailable)	775	
Critical Peak-Pricing (CPP) with Control	-	
Load as a Capacity Resource	1,125	
Total Dispatchanle, Controllable Demand Response	**1,900**	
Total Demand-Side Management	**2,149**	

The OPA, Ontario Energy Board and distributors are responsible for promoting, developing and delivering conservation programs within Ontario. These programs encapsulate a number of different types of conservation measures with the distributors having a great deal of latitude in how they meet their conservation targets. Validation and verification of these savings are the purview of the OPA and distributors.

The IESO quantifies the uncertainty in peak demand due to weather variation through the use of Load Forecast Uncertainty (LFU), which represents the impact on demand of one standard deviation in the underlying weather parameters. For the upcoming winter peak of 22,311 MW, the LFU is 657 MW. Economic factors do not have a significant impact on near-term seasonal assessments.

As part of the IESO's analysis, we use an Extreme weather scenario to analyze the system under duress. The Extreme weather scenario is generated by taking the most severe weather since 1970 on a week by week basis. This gives an "outer envelope" of the conditions that the system may face through the upcoming season.

Generation

The total Existinc-Certain capacity (all installed and operation generation resources) (34,882 MW) and loads as a capacity resource (1,205 MW) connected to the IESO-controlled grid is 36,087 MW, of which the amount of certain capacity is 28,741 MW for December 2011. *Existing-Other* capacity amounts to 6,113 MW for December 2011, which includes the on-peak resource derates, planned outages, and transmission-limited resources. Existing-Inoperable capacity of 28 MW is also identified for the study period.

The certain capacities for January and February are 28,575 MW and 28,956 MW respectively.

The Future capacity additions before the winter months are 93 MW. These are made up of a wind project, Raleigh Wind Energy Centre (78 MW), and the Becker Cogeneration facility (15 MW). Both projects are scheduled to come into service before December 2011. Two coal units (980 MW) at Nanticoke are expected to be shut down by the end of 2011. Two wind projects with a total capacity of 168 MW are scheduled to be in service for January and February 2012.

To model wind resources in the adequacy assessments, the IESO uses an estimated wind capacity contribution during peak demand hours. This model captures wind output during the top 5-contiguous daily peak demand hours for the winter and summer seasons, as well as monthly shoulder periods.[179]

The wind capacity contribution for the winter season, December to February, is estimated at 32.8 percent of the installed capacity. Expected wind output amounts to 438 MW, with an additional 896 MW of derates, for a total nameplate capacity of 1,334 MW as of December 2011 (Table 56). For January and February, the *Existing-Certain* capacity is 518 MW and *Existing-Other* capacity is 1,062 MW. No other variable resources (solar etc.) are connected to the IESO-controlled grid or are expected to be connected in the study period. For biomass, the nameplate capacity is 47 MW, of which 35 MW are expected during the peak demand.

[179] Two sets of wind data are considered: simulated wind data over a fixed 10-year history, and actual wind farm output data collected since March 2006. A conservative approach is employed, which selects the lesser value of the two data sets (simulated vs. actual) for each winter/summer season and shoulder period month. For the seasonal assessments, wind capacity contribution is represented deterministically, by selecting median values observed during the winter and summer seasons and shoulder period months.

Table 56: On-Peak Renewable Resources

Renewable Resource		2011/2012 Winter (MW)
Wind	Expected	438
	Derated	896
	Wind - Total Nameplate Capacity	**1,334**
Solar	Expected	-
	Derated	-
	Solar - Total Nameplate Capacity	**-**
Hydro	Expected	6,189
	Derated	1,758
	Hydro - Total Nameplate Capacity	**7,947**
Biomass	Expected	35
	Derated	12
	Biomass - Total Nameplate Capacity	**47**

IESO resource adequacy assessments include hydroelectric generation capacity contributions based on median historical values of hydroelectric production plus operating reserve provided during weekday peak demand hours. Deviations from median conditions are not anticipated at this time for the upcoming winter. In the operating timeframe, water resources are managed by market participants through market offers to meet the hourly demands of the day. Since most hydro storage facilities are energy limited, hydroelectric operators identify weekly and daily limitations for near-term planning in advance of real-time operations.

The IESO does not anticipate any weather or fuel-related constraints for the province that would reduce generating capacity.

Two coal units with a capacity of about 980 MW will be shut down by end of 2011. Four coal units with a capacity of about 2,000 MW were shut down last year in October. These shut downs are key elements of the Province of Ontario's climate change initiative to phase out coal-fired electricity by 2014. To compensate for the loss of coal generation, more than 4,500 MW of gas-fired generation and 1,300 MW of wind generation have been added since 2006.

Capacity Transactions

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC regional criteria without reliance on external resources. There are no firm imports or exports identified for the winter period.

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.

Transmission

Since last winter, Hydro Ottawa built a new load facility at Ellwood MTS (Municipal Transformer Station) comprising of two 230/13.2 kV transformers. Oakville Hydro built Glenorchy MTS with two 230/28 kV transformers.

There were no significant new transmission additions since last winter. Hydro One installed series compensation on the 500 kV north-south lines at Nobel Switching Station to increase the transfer capability.

The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. This delay impacts the use of the available Ontario generation in the Niagara area, particularly during high demand periods or during outage conditions. Under the conditions expected for this winter studies show that the system is adequate to meet expected demands without this reinforcement.

The failed R76 voltage regulator and the BP76 circuit on the Niagara intertie will not be available for winter. The bypass will remain available for use if required until the R76 voltage regulator returns.

Phase angle regulators (PARs) are installed on the Ontario-Michigan interconnection at Lambton TS on the Ontario side and at Bunce Creek TS in Michigan, representing three of the four interconnections with Michigan. The joint operating agreement has been signed between the IESO and the MISO to operate these PARs. However, an approval from the DOE (Department of Energy - US) is still pending on the joint agreement. The operation of these PARs will enable the IESO and the MISO to control the actual flows on the Ontario-Michigan interconnection equivalent to the scheduled flows within the control deadband (+/-200 MW) and therefore, the PARs will further assist in the managing the system congestion.

Regardless of these outages, Ontario meets all reliability criteria without dependence on any external resources.

Ontario has many operating limits and instructions that could limit transfers under specific conditions, but for the forecast conditions including design-criteria contingencies, sufficient resources and bulk system transfer capability is expected to be available to manage potential congestion and supply forecast demand.

In the winter, Ontario’s theoretical maximum capability for exports could be up to 5,950 MW and coincident imports up to 6,350 MW. These values represent theoretical levels that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has an expected coincident import capability of approximately 4,800 MW.

Operational Issues

The IESO addresses winter extreme weather conditions by doing planning studies using the most severe weather experienced since 1970. Studies show that Ontario will have sufficient reserves over the entire winter period. Available operational and market measures and interconnection capability are evaluated to be sufficient to meet winter energy demands.

The IESO has recently implemented a new planning procedure. This planning procedure relates to operational support staff providing the real-time operators advance warning of possible wind cut-off/ramp events.

Notable surplus base load generation (SBG) conditions are not expected to occur over the winter months of 2011/2012. In case the SBG conditions do occur, beyond typical market actions such as exports, minimum hydro dispatch and nuclear maneuvers, some out of market control actions are available to the IESO to manage any potential or actual SBG conditions.

Demand measures currently comprise about 5 percent of total resources. At these levels, any failure to respond does not pose a significant concern to reliability. Demand measures are grouped into two categories, price sensitive and voluntary. The IESO considers only price sensitive demand for adequacy assessment purposes. There are price and demand triggers that both need to be met in order to deploy the demand response resources. The majority of the IESO's demand response programs have significant financial penalties for non-compliance and as such the demand response programs are deemed reliable.

There are limits on the number of hours that demand response can be called upon, however the number of available calls is sufficient, hence the limits are not seen as an impediment to reliability.

There are no unusual operating conditions, environmental, or regulatory restrictions that are expected to impact reliability for this winter.

Reliability Assessment

The IESO uses a multi-area resource adequacy model, in conjunction with power flow analyses, to determine the deliverability of resources to load. This process is described in the document, "*Method to Perform Long-Term Assessments.*"[180]

The projected Reserve Margins are on average:

- from Existing resources = 36 percent
- from Anticipated resources = 36.3 percent
- from Prospective resources = 40 percent

The Reserve Margin target for Ontario is 21.8 percent based on the NPCC criteria. Planning reserves, determined on the basis of the IESO's requirements for Ontario self-sufficiency, are above target levels over this period for normal weather conditions. On average, the projected Reserve Margins for the upcoming winter are 3.4 percent lower than the projected margin for the last winter.

Reserve requirements are established in conformance with the NPCC regional criteria. The latest study results are published in the 18-Month Outlook.[181]

[180] This document is posted on the IESO web at http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2011may.pdf.
[181] The link to the report is:http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2011aug.pdf.

The IESO works with the Ontario gas transportation industry to identify and address issues. There are communication protocols in effect between the IESO and the gas pipe line operators to manage and share information under tight supply conditions in either sector (gas or electricity).

Generator owners/operators are required to keep sufficient supplies of fuel (e.g., coal, nuclear fuel bundles, etc.). Coal inventories at the coal-fired stations are being carefully managed leading to the end of 2014, when all coal generation has been legislated to cease.

The IESO regularly conducts transmission studies that include results of stability, voltage, thermal, and short-circuit analyses in conformance with NPCC criteria. The IESO’s transmission studies are conducted to comply with the NERC TPL standards, in addition to NPCC criteria.

The IESO has market rules and connection requirements that establish minimum dynamic reactive requirements, and the requirement to operate in voltage control mode for all resources connected to the IESO-controlled grid. In addition, the IESO’s transmission assessment criteria includes requirements for absolute voltage ranges, and permissible voltage changes, transient voltage-dip criteria, steady-state voltage stability and requirements for adequate margin demonstrated via pre and post-contingency P-V curve analysis. These requirements are applied in facility planning studies. Operating security limit studies review and confirm the limiting phenomena identified in planning studies.

Assessment Area Description

The province of Ontario covers an area of 1,000,000 square kilometres (415,000 square miles) with a population of 13 million. The Independent Electricity System Operator (IESO)[182] as the Reliability Coordinator and Balancing Authority for the Province of Ontario directs the operations of the IESO-controlled grid (ICG) and administers the electricity market. The ICG experiences its peak demand during the summer, although winter peaks still remain strong.

[182] The Independent System Operator of Ontario (IESO) website is: http://www.ieso.ca.

NPCC–Québec

Introduction

The Québec Subregion is a NERC subregion in the northeastern part of the NPCC Region. Hydro-Québec (the main utility in the Area) ensures generation (through Hydro-Québec Production), transmission (through TransÉnergie) and distribution (through Hydro-Québec Distribution) services for its internal load and point to point transmission services for wholesale customers through its interconnections with neighboring Areas. There are other systems in the subregion which are interconnected with TransÉnergie's grid mostly with their own generation, and transmission to feed their industrial loads. TransÉnergie, Hydro-Québec's transmission division, acts as Balancing Authority, Reliability Coordinator, Transmission Planner, and system controller for the area. The regulatory body in Québec is the Régie de l'énergie du Québec[183] (Québec Energy Board).

The Québec Subregion is a winter-peaking area because of the large amount of space heating load that is present during Winter Operating Periods. The all-time internal peak hourly demand is 37,717 MW set on January 24, 2011. Summer peak demands are of the order of 22,000 MW (About 57 percent of peak winter demand). Summer Operating Periods are usually characterized by extensive generation and transmission maintenance in preparation for the upcoming winter. One other important characteristic is that generation on the system is made of approximately 94 percent hydro based resources. This has dictated the development of the system over the years, as large remote river systems have been gradually developed. Installed capacity for the 2011/2012 Winter Operating Period is 43,394 MW.

Transmission voltages are 735, 315, 230, 161, and 120 kV with a ± 450 kV HVDC multi-terminal line. Transmission line length totals 33,453 km (20,787 miles). Installed Capacity will be 43,394 MW for the 2011/2012 Winter Peak period.

The Québec subregion is one of the four NERC Interconnections in North America. There are interconnections with Ontario, New York, New England, and the Maritimes, which consist either of HVDC ties or radial generation or load to and from neighboring systems.

This section will briefly discuss demand forecasts, generation availability, capacity transactions, resource adequacy, transmission adequacy, operational issues, and reliability.

At this time, no reliability issues of any kind are forecasted for the upcoming Winter 2011/2012 Operating Period.

Demand

Assumptions

Weather assumptions for demand forecasts are based on the average climatic conditions observed from 1971 to 2006 (36 years) adjusted for a global warning effect of 0.30 degree Celsius (°C) per decade starting in 1971. Climatic uncertainty is modeled by recreating each hour of this 36-year period under

[183]The Régie de l'énergie - Gouvernement du Québec: http://www.regie-energie.qc.ca/en/index.html.

current load forecast conditions.[184] Given global uncertainty parameters and assuming a normal distribution for load uncertainty, the peak demand standard deviation is 1,560 MW for the 2011/2012 Winter Operating Period.

Economic, demographic and energy-use assumptions used in this load forecast are consistent with the first progress report of Hydro-Québec Distribution's (HQD) 2011-2020 Procurement Plan to be filed with the Régie de l'énergie du Québec (Québec Energy Board) in November 2011. This report will be available on the Québec Energy Board website in early November.

Last winter's actual peak was 37,717 MW occurring on January 24, 2011 at 8h00 EST (Table 57). Global system needs, including exports, were about 40,200 MW at that time. This was the all-time internal winter peak record for Québec. Last year's peak demand occurred in colder weather conditions than average.

Table 57: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**37,153**	**January-2012**
2010/2011 Forecast	36,945	January-2011
2010/2011 Actual	37,717	January-2011
All-Time Peak	37,717	January-2011

Forecast

The internal demand forecast for 2011/2012 winter is 37,153 MW. This forecast is 208 MW higher than the last year's winter forecast of 36,945 MW. (+0.6 percent). This is mainly due to an increase in space heating in the residential and commercial sectors.

Hydro-Québec Distribution conducts its load forecast for the Québec subregion represented as a single entity. There is no demand aggregating and the Area's peak forecast information is coincident. Resource adequacy evaluations are based on winter peak conditions, with low, base, and high case scenarios. The average demand forecast with uncertainties is modeled through Monte Carlo simulations.

Demand Side Management

There are two interruptible load programs in Québec totalling 1,430 MW. Each program addresses different industrial customers. Moreover, the area can rely on 250 MW of direct control load management under the form of voltage reduction. Thus, for this Winter Operating Period in Québec Demand Response Programs total 1,680 MW (Table 58). These programs represent about 4.5 percent of the internal demand forecast.

[184] Moreover, each year of historical data is shifted up to ± 3 days to gain information on conditions that occurred during either a weekend or a week day. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of those 252 scenarios.

Table 58: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**-**
Non-Controllable Demand-Side Management	
Direct Control Load Management	250
Contractually Interruptible (Curtailable)	1,430
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**1,680**
Total Demand-Side Management	**1,680**

Interruptible load programs are planned with participating industrial customers with whom contracts have been signed. All customers are regularly contacted before the peak period (generally during autumn) so that their commitment to provide their capacity when called during peak periods is ascertained. These programs have been in operation for a number of years and according to the records, customer response is highly reliable. When interruptible load is called, actual customer load is measured and archived for post-mortem analysis, if needed.

Extensive testing of the 250 MW voltage reduction system has prompted HQD to include it in its Demand Response Portfolio. TransÉnergie has a yearly verification agenda for this program including functional testing of every substation where the scheme is implemented and global testing of the system to assess demand response. This program is not expected to vary considerably in the near future.

Energy Efficiency

Hydro-Québec Distribution presents – on a yearly basis – its Energy Efficiency Plan Update, entitled: Plan global en efficacité énergétique (PGEÉ),[185] to the Québec Energy Board for the next and upcoming years. Capacity contributions of different programs implemented by Hydro-Québec in the last few years are estimated to be about 1,530 MW at peak. Of this amount, the PGEÉ program contributes about 920 MW.

PGEÉ[186] focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers.

There are available residential customer programs and tools for promoting energy savings that include old refrigerator recycling, electronic thermostats, low-energy lighting, etc. Other programs for business customers are also available.

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[185] http://internet.regie-energie.qc.ca/Depot/Projets/99/Documents/R-3758-2011-B-0112-DEMAMEND-PIECE-2011_09_12.pdf.

[186] Energy Efficiency Program features can be found on Hydro-Québec's website: http://www.hydroquebec.com/energywise /index.html.

In addition to these energy saving programs, a “dual energy” program has been ongoing for some years in Québec. Recently, the number of interested customers has increased. Program subscribers are fitted with automatic devices that switch from electrical energy to fuel as a heating source when outdoor temperature is -12°C or lower. According to the most recent program evaluations the peak load for next winter would be 860 MW higher without this program.

Demand Variability
For the next winter, overall uncertainty (one standard deviation) represents ± 1,560 MW around the peak forecast. This figure combines climatic uncertainty, which accounts for 1,400 MW (one standard deviation) and load forecast uncertainty that reached 688 MW.

No changes have been made to the load forecast method due to the economic recession. In this assessment, the load forecast is based on a conservative economic recovery scenario.

Due to the winter peaking characteristic of the system, the Québec Subregion obviously explicitly addresses winter conditions in assessing variability in projected demand.

Extreme cold weather results in a large load pickup over the normal demand forecast. This situation is addressed at the planning stage through TransÉnergie’s Transmission Design Criteria. When designing the system, one particular criterion edicts that both steady state and stability assessments be made with winter scenarios involving demands 4,000 MW higher than the normal weather peak demand forecast. This is equivalent to 111 percent of peak winter demand. This ensures that the system is designed to carry the resulting transfers while conforming to all design criteria.

Resources needed to feed the load during such episodes must be planned and provided by Hydro-Québec Distribution, the Load Serving Entity.

Generation
The vast majority of capacity resources in the Québec Subregion are hydroelectric resources.
Resources consist of:

- Existing Certain Resources: 40,064 MW
- Existing Other Resources: 2,333 MW
- Existing Inoperable Resources: 997 MW

HQP has just placed the 768-MW Eastmain-1-A hydro G.S. in-service and is preparing to commission the 150-MW La Sarcelle hydro G.S. If other outages were to occur, system reliability would be maintained through the use of interconnections with neighboring NPCC areas, most of which are summer-peaking.

Variable resources in the subregion are mostly wind generating resources. Wind generation plants are owned and operated by Independent Power Producers (IPPs). Nameplate capacity will be 1,057 MW for the 2011/2012 winter peak period of which 212 MW is under contract with Hydro-Québec Production (HQP) and is de-rated by 100 percent for this assessment. The rest (845 MW) is under contract with HQD and is derated by 70 percent for this assessment. This is based on detailed wind capacity credit evaluations by HQD which have been presented to the Régie de l'énergie du Québec (Québec Energy

Board). The related report is available (in French only) on the Québec Energy Board website.[187] An English article was presented in October 2010 in a workshop dedicated to wind power impacts on power systems.[188]

Moreover, a small amount of the capacity in the Québec Subregion is generated by biomass. This is approximately 172 MW.

Hydro Conditions and Fuel Supply

Hydro conditions for this upcoming Winter Operating Period are such that reservoir levels are sufficient to meet both peak demand and daily energy demand throughout winter. To assess its energy reliability Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to go through a sequence of 2 consecutive years of low water inflows totalling 64 TWh or a sequence of 4 years totalling 98 TWh and having a 2 percent probability of occurrence. The system's internal annual consumption is approximately 184 TWh. Reliability assessments based on this criterion are presented three times a year to the Québec Energy Board. The document can be found on the Régie de l'énergie's website[189].

Fuel supply and transportation is not an issue in Québec, as fossil fuel generation is used for peaking purpose only and adequate supplies are stored nearby. No other conditions that would create capacity reductions are expected for the 2011/2012 winter period.

Inoperable Generation

As was mentioned in previous assessments, the 547-MW natural gas unit operated by TransCanada Energy at Bécancour has been mothballed for the last four years. On June 10, 2011, HQD filed a request with the Québec Energy Board to renew the temporary shutdown for 2012. This shutdown for year 2012 was approved by the Régie on August 2, 2011.

It was also mentioned in last winter's assessment that a 150 MW fossil fuel unit was out of service. This unit at Tracy Generating Station (G.S.) has now been definitely retired. Moreover, the three remaining units have now been mothballed by Hydro-Québec Production. Existing Inoperable Resources now total 997 MW. These outages do not affect system reliability.

Capacity Transactions

Imports

The Québec Balancing Authority area will need to purchase about 100 MW on short term markets to ensure resource adequacy for the 2011/2012 Winter Operating Period.

Each year, the Load Serving Entity in Québec (HQD) proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed. These purchases may be supplied by resources

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[187] http://www.regie-energie.qc.ca/audiences/Suivis/Suivi_HQD_PlanAppro.html.

[188] L. Bernier, A. Sennoun, "Evaluating the Capacity Credit of Wind generation in Québec", 9th International Workshop on Large Scale Integration of Wind Power into power Systems as well as on Transmission Networks for Offshore Wind power Plants, 18-19 October 2010, Québec City, Canada.

[189] http://www.regie-energie.qc.ca/audiences/Suivis/Suivi_HQD_CriteresFiabilite_D-2008-133.html.

located in Québec or in neighboring markets. In this regard, HQD has designated the Massena-Châteauguay (1,000 MW) and the Dennison-Langlois (100 MW) interconnections to meet its resource requirements during winter peak periods.

All capacity purchases needed to ensure resource adequacy for the 2011/2012 winter operating period will be backed by firm contracts for both generation and transmission.

Moreover, all purchases (if required) into the Québec subregion are subject to damages for delivery failures.

Exports

In January and February the Québec Subregion has secured firm contracts for total exports of 755 MW to New England (310 MW), Ontario (145 MW) and New Brunswick (300 MW). In December, a sale of 250 MW to New York is expected and the sale to New Brunswick is 100 MW. (Total of 805 MW).

Firm generation and transmission have been secured for all these transactions. There are no Export transactions defined as Liquidated damage Contracts for next winter (Table 59).

Table 59: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	90
	Expected	-
	Non-Firm	-
	Total	**90**
Exports	Firm	755
	Expected	-
	Non-Firm	-
	Total	**755**
	Net Transactions	**(665)**

Emergency Imports

Finally, for the next Winter Operating Period, it is not expected that the Québec Balancing Authority area will have to rely on outside assistance or external resources for emergency imports.

Transmission

Following are the significant new bulk power transmission facilities anticipated to be in-service for this winter that were added since last winter.

Transmission Lines

It was mentioned in the NERC 2011 Summer Reliability Assessment that 315 kV lines to integrate Eastmain-1-A and La Sarcelle Generating Stations were being built. The 315 kV transmission for these stations is now in service. Other 315, 230, 161, and 120 kV transmission will be placed in service (or is already in service in some cases) to integrate new wind capacity before the winter peak period.

Transformers

No new significant transformers are planned in-service for the peak period, except for the Eastmain-1-A and La Sarcelle station step-up transformers to be placed in-service as the corresponding units are commissioned.

Significant Substation Equipment

Two major projects to enhance system reliability are being commissioned for the 2011/2012 peak period. First, at Chénier 735 kV substation (North of Montréal), TransÉnergie is placing two -300/+300 Mvar Static Var Compensators (SVCs) in service. Second, a 735 kV series compensation project is being finalized at Jacques-Cartier 735/315 kV substation (Near Québec City) on lines 7024 and 7025. Each of these two lines will now have 35 percent series compensation.

Moreover, two 345-Mvar, 315 kV shunt capacitor banks will be placed in-service around the Montréal area for the peak period.

This equipment is added for the System Reinforcement Project required by TransÉnergie and for the 2 X 1,200 MW firm point to point transmission service requested by Hydro-Québec Production.

There are no concerns in meeting target in-service dates for TransÉnergie's new transmission additions.

Outages

No significant transmission lines and transformers are expected to be out-of-service during the upcoming winter season. As mentioned earlier, the Québec Balancing Authority area is winter peaking and as such, line and transformer maintenance is normally scheduled during the Summer Operating Period and ends December 1st.

Moreover, no internal transmission constraints that could significantly impact reliability are expected during this winter season. No maintenance is scheduled that will impact interconnection transfer capability to other subregions during peak periods.

One of three synchronous condensers at the Duvernay substation in the Montréal area, Synchronous Condenser CS23, will remain out of service for the 2011/2012 winter operating period. Synchronous Condenser CS23 originally became unavailable in June of 2008 due to a major transformer fault; a new replacement transformer for Synchronous Condenser CS23 failed as well while undergoing commissioning tests (failure of the load tap changer). The two remaining synchronous condensers continue to be available at the Duvernay substation. The unavailability of one of three synchronous condensers at the Duvernay substation results in an incremental reduction in transfer capability of 100 MW to 400 MW on three 735 kV interfaces on the Québec system. However, normal transfer capability on these interfaces is usually well over 10,000 MW so that this is not expected to significantly impact transmission reliability for the 2011/2012 Winter Operating Period. Actual operations during the 2008/2009 and 2010/2011 winter operating periods demonstrated that the absence of the one synchronous condensers at Duvernay had minimal impact.

No other major transmission equipment is expected to be out of service for this winter period.

Interconnection Transfer Capabilities

The interregional transfer capabilities out of and into Québec with its neighboring systems for the 2011/2012 Winter Operating Period are shown below (Table 60).[190] These limits represent Normal Transfer Capability (NTC) values for the Winter Operating Period. Actual Feasible Transfer Capability (FTC) values during peak periods in Québec may be lower. For example, the limit into Québec from New England (Sandy Pond) at the Québec peak is zero because the interconnection is required for internal Québec transmission needs.

Both NTC and FTC values are presented in NPCC Seasonal Reliability Assessments, with accompanying text explaining the rationale for any constraint, if needed.[191]

Table 60: 2011/2012 Winter Interconnection Normal Transfer Capability

Interconnection	Outbound Limits (MW)	Inbound Limits (MW)
Ontario North (D4Z, H4Z)	85	85
Ontario Ottawa (X2Y, P33C, Q4C)	410	140
Ontario Brookfield (D5A, H9A)	250	110
Ontario Beauharnois (B5D, B31L)	800	470
Ontario Ottawa (Outaouais)	1,250	1,250
New York (CD11, CD22)	325	100
New York (7040)	1,500	1,000
New England (Highgate)	220	170
New England (Stanstead-Derby)	50	0
New England (Sandy Pond)	2,000	2,000
New Brunswick (Madawaska + Eel River)	1,029	770

These limits recognize transmission or generation constraints in both Québec and its neighbors. They are reviewed periodically with neighboring systems and are posted in NPCC Reliability Assessments. These limits may not exactly correspond to other numbers posted in Hydro-Québec's Annual Reports or on TransÉnergie's website. Such numbers are maximum import/export capabilities available at any one time of the year. Moreover, these limits do not correspond to TTC or ATC values posted on the OASIS; they are only intended to offer a global picture of transfer capabilities to the readers of this assessment.

Operational Issues

Operating Studies

In its review of resource adequacy for the NPCC, HQD includes a high load forecast scenario. Economic, demographic and energy parameters used for the study are set higher relative to the base case scenario. Load uncertainty then becomes dependent on weather conditions only. If the Resource Adequacy criterion is not met, actions to restore reliability are identified and established (new calls for tenders, new interruptible load contracts or an in-service date for new generation units sooner than expected).

Moreover, TransÉnergie continually performs load flow and stability studies to assess system reliability and transfer capabilities on all its internal interfaces. A peak load study is performed annually integrating

[190] Limits obtained and updated from the NPCC Reliability Assessment for Winter 2011/2012.

[191] http://www.npcc.org/documents/reports/Seasonal.aspx.

new generation, new transmission and the latest demand forecasts as well as any unusual operating conditions such as generation and transmission outages. Extreme cold weather conditions result in a large load pickup over the normal weather forecast and are included in TransÉnergie's Transmission Design Criteria.[192] This is equivalent to 111 percent of peak winter demand.

The Québec subregion also participates with neighboring Areas in seasonal CO-12 and CP-8 NPCC Working Group assessments of system reliability.

As mentioned in previous assessments, a number of projects have been or are being implemented to cope with certain issues such as North to South transfer increases, voltage variations on the system and new point-to-point firm transmission services.

Upgrades to the system for 2012 have also been presented in the last NPCC Comprehensive Review Assessment of the Québec Transmission System for 2012.

As mentioned earlier in the Transmission section, there is an operational issue with Synchronous Condenser CS23 at Duvernay substation for the winter period. The condenser's transformer (18/315 kV) has suffered a major failure. The Duvernay Synchronous Condenser outage causes 100 to 400 MW of restrictions on three 735 kV interfaces on the system.

No other particular operational problems have been observed for the oncoming 2011/2012 Winter Operating Period.

Operating Issues

Integration of wind resources is ongoing in Québec. Up to 3,350 MW will be integrated into the system through 2015; it is expected that 1,057 MW of nameplate capacity will be on-line for the 2011/2012 Winter Operating Period. This has not yet led to any special System Operating Procedures resulting from the integration of wind resources in Québec.

Moreover, the Area does not anticipate any reliability concerns resulting from minimum demand and over generation resulting from variable resources for the 2011/2012 Winter Operating Period. In Québec, minimum demand periods occur during Summer Operating Periods. A certain amount of hydro generation at run of the river installations must be generated along with wind generation on the system ─ which may be contributing if the right conditions occur ─ so that such conditions may occur on the longer term during summer. Most of the generation in the Area is hydro with medium or large reservoirs and can be modulated to follow load variations. Periods of lower demand in summer usually coincide with periods of higher transfers from Québec to neighboring Areas (with summer peaking characteristics) which alleviates this potential problem.

No reliability concerns resulting from actual levels of Demand Response resources are anticipated. Demand Response resources in the Québec Subregion consist only of interruptible load programs

[192] When designing the system, both steady state and stability assessments are made with winter scenarios involving demands 4,000 MW higher than the normal weather peak demand forecast.

totaling approximately 1,430 MW which are used only during Winter Operating Periods. Contracts with large high voltage industrial customers and smaller industrial customers allow precise use of Demand Response according to system needs at specific times and intervals during the Winter Operating Period.

Interruptible load programs are planned and contracted with participating industrial customers including the amount of load to be interrupted, the number of times that load may be interrupted on a daily or seasonal basis, and any other relevant detail. All customers are regularly contacted before the peak period (generally during autumn) so that their commitment to provide their capacity when called during peak periods is ascertained. On an operations time-base a number of operating instructions and procedures manage the various Demand Response programs. Individual contact names are actually filed into the procedures along with a contact process. Response to calls for interrupting load is historically excellent. A follow-up file of response to interrupting load calls is continually updated by the system controller for post-mortem analysis.

Another 250 MW available at peak through a voltage reduction scheme is also considered as Demand Response by Hydro-Québec Distribution and is not expected to vary considerably in the near future. TransÉnergie regularly tests its voltage reduction scheme to ascertain its availability and the actual demand response characteristics.

There are no environmental and/or regulatory restrictions that could impact reliability in Québec for the 2011/2012 Winter Operating Period. A number of peaking thermal units (Gas turbines) totaling 716 MW may be used a few times during any Winter Operating Period to provide peaking capacity but the energy content associated with this use is quite small.

No other unusual operating conditions that could significantly impact reliability for the upcoming winter are anticipated in Québec.

Reliability Assessment

Resource Adequacy

Hydro-Québec Distribution bases its resource adequacy requirements on a probabilistic loss-of-load expectation analysis using a multi-area resource adequacy model. The criterion used by HQD is that of NPCC as stated in NPCC Directory #1 – "Design and Operation of the Bulk Power System". Resource adequacy is assessed through NPCC Reviews of Resource Adequacy presented regularly to the Reliability Coordinating Committee. These may be Interim Reviews or Comprehensive Reviews as required by NPCC.

To assess its resource adequacy, the Québec Subregion uses a Loss-of-Load-Expectation (LOLE) method. The simulation model is represented by an hourly load system. Transmission capability within the system is also modeled. Adequacy is based on the Resource Adequacy Criterion of the NPCC Reliability Reference Directory #1 – "Design and Operation of the Bulk Power System".[193]

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[193] "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per

In this assessment, existing and anticipated Reserve Margins are equal to 10.6 percent and the prospective Reserve Margin is equal to 10.7 percent for the 2011/2012 Winter Operating Period. All Reserve Margins are above the Québec Reference Reserve Margin Requirement of 9.7 percent for the current year as stated in the 2010 Québec Interim Review of Resource Adequacy submitted to NPCC (generally, the required Reserve Margin varies between 9 and 10 percent).

The 2011/2012 winter's projected Reserve Margin of 10.6 percent is almost the same as last winter's 10.4 percent projected Reserve Margin. Despite an increase of the available capacity due to capacity additions to the Québec system and an upward revision of the forecasted levels of reservoirs due to better than normal inflows in 2011 compared to 2010, the projected Reserve Margin remains the same. This is explained by a forecasted internal demand increase (+208 MW) and by the mothballing of Tracy fossil fuel G.S. (-450 MW). The Reserve Margin is above the Reference Reserve Margin Requirement of 9.7 percent and should not be of concern for the Area's reliability because of the nature of the power system. In fact, more than 90 percent of generation is hydro. Outage rates are lower than for other types of generation (coal, oil, etc.) and less maintenance is required. Moreover, the Load Serving Entity (HQD) can rely on additional potential purchases of up to 1,000 MW as designated resources to satisfy Québec internal demand if required.

For January, the projected Reserve Margins are:

- Existing Certain Reserve Margin = 10.6 percent
- Anticipated Capacity Reserve Margin = 10.6 percent
- Prospective Capacity Reserve Margin = 10.7 percent

The latest resource adequacy review for the upcoming winter was the 2010 Interim Review of resource adequacy. In this study, it was found that the required Reserve Margin for the 2011/2012 winter peak period was 9.8 percent over a one-year horizon while the planned Reserve Margin was 12.7 percent. Total planned capacity was 42,612 MW at the time. This study has shown that the Québec Balancing Authority Area complies with the NPCC resource adequacy criterion requiring a Loss of Load Expectation (LOLE) of less than 0.1 day per year. The LOLE for the 2011/2012 winter period was 0.03 day per year.[194]

The Québec Subregion fossil fuel generation is used for peaking purposes only. The energy contribution from these generating stations is minimal. All have adequate fuel reserves as part of their installations and all are fueled at the beginning of the Winter Operating Period.

Fuel supply and transportation is not an issue in Québec. No other conditions that would create capacity reductions are expected for the 2011/2012 winter period.

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year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages rates and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available procedures."

[194] The 2010 Québec Interim Review of Resource Adequacy can be found at the following web site: http://www.npcc.org/documents/reviews/Resource.aspx.

Transmission

Transient and voltage stability studies are performed continuously by TransÉnergie (Transmission Planner) to establish transfer limits on all interfaces. No particular problems are anticipated for this Winter Operating Period.

It has already been mentioned in previous NERC Seasonal Assessments that voltage support in the southern part of the system (load area) is a concern during Winter Operating Periods especially during episodes of heavy load. Hydro-Québec Production (the largest producer on the system) ensures that maintenance on generating units is finished by December 1, and that all possible generation is available. This, along with yearly testing of reactive capability of the generators, ensures maximum availability of both active and reactive power. The end of TransÉnergie maintenance on the high voltage transmission system is also targeted for December 1. Also, TransÉnergie has a target for the availability of both high voltage and low voltage capacitor banks. No more than 300 MVAr of high voltage banks on a total capacity of approximately 9,500 MVAr should be unavailable during Winter Operating Periods. The target for the low voltage banks is 90 percent availability based on installed capacity in the load area of the system (About 5,500 MVAr).

Voltage variations on the high voltage transmission system are also of some concern. These are normal variations due to changes in transmitted power from North to South during load pickup and interconnection ramping. Under peak load conditions, these variations may be large enough to trigger the Automatic Shunt Reactor Switching System and must be contained. In 2008 TransÉnergie had recommended and undertaken a number of actions to optimize shunt reactor switching, as mentioned in previous NERC Winter Assessments. Moreover, TransÉnergie has recently enacted a new Transmission Design Criterion concerning voltage variations on the system.[195]

Assessment Area Description

Geographically, the Québec Balancing Authority Area is a NERC subregion in the northeastern part of the NPCC Region. Population served is around seven million. The Québec Subregion covers about 1,668,000 square kilometers (644,300 square miles) but most of the population is grouped along the St. Lawrence River Basin and the largest load area is in the southwest part of the Area, mainly around the Greater Montréal area, extending down to the Québec City area.

[195] This criterion quantifies acceptable voltage variations due to load pickup and/or interconnection ramping. All planning and operating studies must now conform to this criterion.

PJM

Executive Summary

The projection for the 2011/12 PJM RTO winter peak is 130,711 MW, an increase of 15,965 MW, or 12.2 percent, higher than the projected 2010/11 winter peak of 114,746 MW. The forecast is sharply higher because of the integration of the American Transmission Systems, Inc. (ATSI) portion of FirstEnergy, Cleveland Public power (CPP), Duke Energy Ohio and Duke Energy Kentucky (DEOK) into PJM since last winter. The total PJM generation resources expected to be in service during the 2011-2012 winter peak period is approximately 180,406 MW. PJM has contractually interruptible demand side management of 11,826 MW available to the PJM operators through May 31, 2012. This totals 199,232 MW of Existing resources that are considered to be *Existing-Certain*. PJM has added a total of 16,580 MW *Existing-Certain* resources since the 2010-2011 winter season. No Future resources are expected to be added during the assessment period. The generating resources of ATSI, DEOK have been added since the last assessment period. There have been no significant retirements. The PJM projected (existing and prospective margins are the same) Reserve Margin for winter 2011-2012 is 48 percent. This level is well in excess of the required Reserve Margin of 15.5 percent. No Subregions exist in PJM. Since PJM is summer peaking, very few reliability concerns occur in the winter except for extreme weather that usually effects distribution more than the Bulk Electric System.

The Trans-Allegheny Interstate Line (TrAIL)500 kV line in the Allegheny Power/Dominion areas has increased import capability into the Baltimore/Washington/Northern Virginia area by approximately 1,000 MW. The AP South Interface capability has increased by approximately 500 MW. The Carson-Suffolk 500 kV Line in Dominion is now in service. It will strengthen the transmission system to the southern Dominion area. No significant transmission additions will occur this winter. No reliability concerns are expected this winter.

Operations during extreme weather events challenge the operators in PJM and our Transmission Owners the most during the winter season.

Introduction

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. Along with being a Regional Transmission Operator, PJM is a Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner and Transmission Service Provider for its footprint. PJM is the largest wholesale market in the world with an all-time peak load of over 156,000 MW.

During the summer of 2011, the American Transmission System Inc. (ATSI) portion of FirstEnergy has joined PJM and its load and generation are included in this winter's pre-seasonal assessment. FirstEnergy is now fully in PJM. Cleveland Public Power also joined PJM in the summer of 2011. Duke Energy Ohio and Kentucky will join PJM on January 1, 2012.

Demand

The demand forecast represents the median forecast of a Monte Carlo simulation employing actual weather observations from over thirty years of history. Economic assumptions are based on projected growth in Gross Metropolitan Product for 36 metropolitan areas across the PJM RTO, produced by Moody's Analytics as of December 2010 and revised in January 2011 for three Ohio metropolitan areas (Cleveland, Cincinnati, and Dayton). The PJM RTO winter peak for 2010/2011 was 115,535 MW on December 14, 2010 at hour ending 19:00. The Total Internal Demand projection for the 2010/2011 PJM RTO winter peak was 114,746 MW while the Total Internal Demand projection for the 2011/2012 PJM RTO winter peak is 130,711 MW (Table 61).

Table 61: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**130,711**	**January-2012**
2010/2011 Forecast	114,746	January-2011
2010/2011 Actual	115,535	December-2010
All-Time Peak	118,800	February-2007

The significant increase reflects the integration of the American Transmission Systems, Inc. (ATSI) and Cleveland Public Power on June 1, 2011 and Duke Energy Ohio/Kentucky (DEOK) on January 1, 2012, offsetting the impacts of a weaker economic forecast, and an increase in expected Load Management and Energy Efficiency impacts. PJM models both the non-coincident and coincident loads of all members. The peak conditions on which PJM's resource evaluations are conducted based on are the coincident loads. PJM is a summer peaking region with the typical winter peak being about 84 percent of the summer peak.

PJM has contractually interruptible demand side management of 11,826 MW available to the PJM operators. The resources are registered in PJM's Load Management program. The total effects of demand response can reduce PJM's 2011-2012 winter Total Internal Demand by 9 percent. Participants submit load data from the EDC meters used for retail service or from meters meeting PJM's standards[196] (Section 10.6). Energy Efficiency programs included in the 2011 PJM Load Forecast Report are impacts approved for use in the PJM Reliability Pricing Model (RPM). At time of the 2011 load forecast publication, 170 MW and 386 MW of Energy Efficiency programs have been approved as RPM resources in 2011 and 2012 respectively. Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B.[197] To demonstrate the value of an energy efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing Measurement and Verification plans, providing post-installation M&V reports, and undergoing a Measurement and Verification audit.

Quantitative analysis was done to assess the weather uncertainty of the projected demand. Using a Monte Carlo simulation employing actual weather observations from over thirty years of history it is estimated that the 90/10 load for Winter 2011/2012 is 138,562 MW which is 7,851 MW (or 6 percent)

[196] http://www.pjm.com/~/media/documents/manuals/m11.ashx.
[197] http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

above the Total Internal Demand expected load. No changes were made to the load forecast method used for the 2011 PJM Load Forecast Report due to the economic recession. A downward revision to the economic outlook from Moody's Analytics for the PJM area has resulted in lower peak and energy forecasts in the 2011 PJM Load Forecast Report, compared to the same year in the 2010 Load Forecast Report. Extreme weather conditions are explicitly addressed as part of emergency import analysis for PJM's Locational Deliverability Areas.

Demand

The total PJM resources expected to be in service during the 2011-2012 winter peak period is approximately 180,406 MW. Variable generation amounts to 5,200 MW nameplate and 682 MW expected on peak. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor. PJM has 896 MW of Biomass. Biomass is counted fully in capacity calculations. The North Anna nuclear power station has returned to service following the August 23rd earthquake.

Variable generation amounts to 5,200 MW nameplate and 682 MW expected on peak. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors which are 13 percent for wind and 38 percent for solar for their capacity contribution during peak load conditions. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After gathering three years of operation data, the three-year historic performance over the peak period is used to determine the individual unit's capacity contribution during peak period. PJM has 896 MW of Biomass. Biomass is fully counted in capacity calculations.

Anticipated hydro conditions for the winter are normal. Reservoir levels are at maximum after two late summer post-hurricane rain events. Many dams had to spill significant amounts of water. Hydro conditions will be sufficient to meet both peak demand and the daily energy demand throughout the winter peak period. PJM is not experiencing or expecting conditions that would reduce capacity.

We do not anticipate any existing significant generating units that may affect reliability being out-of-service or retired during the winter season.

Capacity Transactions

PJM has firm capacity imports of 3,858 MW (Table 62). No non-firm imports are considered in this reliability analysis. There are no Expected or Provisional transactions counted towards meeting the Reserve Margin requirements. All transactions are firm for both generation and transmission. No imports are based on partial path reservations. There are no transactions with LDC clauses or “make-whole” contracts.

Table 62: On-Peak Capacity Transactions

	Transaction Type	Winter 2011/2012 (MW)
Imports	Firm	3,858
	Expected	-
	Non-Firm	-
	Total	**3,858**
Exports	Firm	2,598
	Expected	-
	Non-Firm	-
	Total	**2,598**
	Net Transactions	**1,260**

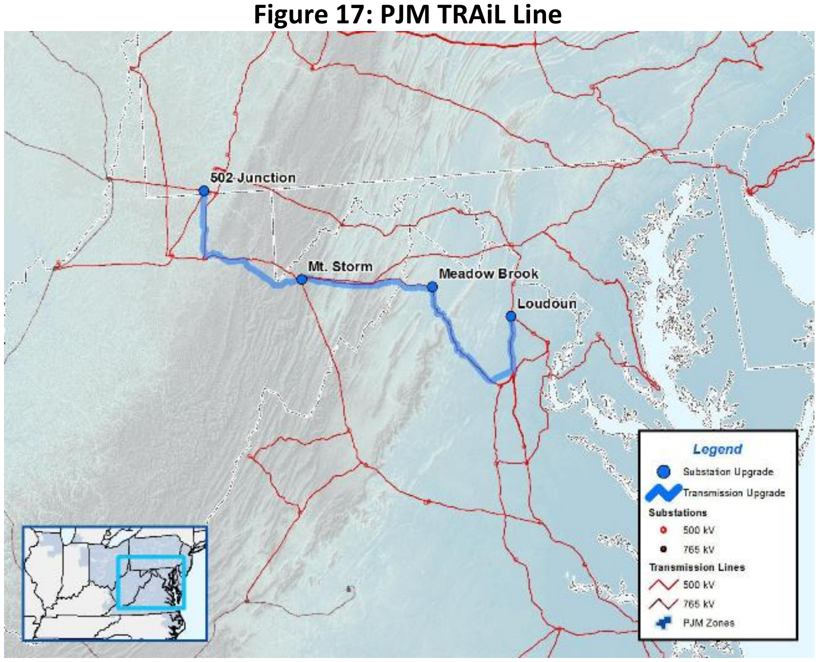
PJM has firm capacity exports of 2,598 MW. No non-firm exports are considered in this reliability analysis. There are no Expected or Provisional transactions in place. All transactions are firm for both generation and transmission. No imports are based on partial path reservations. There are no transactions with LDC clauses or "make-whole" contracts

PJM does not rely on any external emergency assistance for meeting its reserve requirement.

Transmission

The TrAIL 500kV Line in the Allegheny Power/Dominion areas has increased import capability into the Baltimore/Washington/Northern Virginia area by approximately 1,000 MW (Figure 17). The AP South Interface capability is increased by approximately 500 MW. Meadowbrook to Loudoun 500 kV line was energized on April 13, 2011. Mt. Storm to Meadowbrook 500 kV line was energized on May 13, 2011 and the 502 Junction to Mt. Storm 500 kV line was energized on May 20, 2011. The Carson-Suffolk 500 kV line in Dominion is now in service. It will strengthen transmission system to the southern Dominion area.

Figure 17: PJM TRAiL Line



In the Allegheny Power portion of FirstEnergy, two 500/230 kV transformers at the Doubs substation were replaced. A fourth 500/138 kV transformer was added at the Cabot substation. The Wylie Ridge 345/138 kV #2 transformer was replaced. In Baltimore Gas and Electric, the Waugh Chapel 500/230 kV 3-phase transformer was replaced with single phase banks. In Commonwealth Edison, a third Gooding Grove Red 345/138 kV transformer was added. In Dominion Virginia Power a second Suffolk 500/230 kV transformer was added. In PEPCO, a second Burches Hill 500/230 kV transformer was added. In AEP, a 345/138 kV transformer was added at the Don Marquis substation.

No other significant substation equipment was added since last winter. There are no concerns in meeting target in-service dates for new transmission additions.

Concerning planned transmission outages:

- Nelson-Electric Junction 345 kV (1/09/2012-4/27/2012). This outage is required to reconductor the Nelson to Electric Junction line. The Nelson-Electric Junction 345 kV line outage will have an impact on the transfer capabilities between MISO and the ComEd transmission area, especially during periods of high wind generation output. Market-to-Market redispatch between PJM and MISO will be required to control transmission loading.
- Kincaid 2102 345 kV line (1/07/2012-2/15/2012). This outage is required to raise towers and to mitigate sag violation. Kincaid Special Protection Scheme will be enabled during this outage.
- Burches Hill-Chalk Point (9/12/2011-6/01/2012). Burches Hill-Chalk Point 500 kV and New Freedom-Orchard 500 kV line outages should not have significant impact on the system reliability.
- New Freedom-Orchard (1/08/2012-2/10/2012). This outage is for clearance only to install OPGW wire, restoration time is 4 hours.

PJM does not have any transmission constraints that could significantly impact reliability. Interregional transfer capabilities are adequate and include coordination with our neighbors to include any limiting elements on their system.

Operational Issues

PJM performs an Operation Analysis Task Force (self assessment) and interregional assessment(s) using expected peak winter conditions to determine system adequacy and to identify system problems. No unique issues were observed. PJM operates all resources in a consistent manner through cost-effective redispatch procedures. PJM has established procedures to mitigate the impact of minimum demand conditions. No reliability concerns are anticipated.

PJM is a summer peaking RTO. PJM does not project the need to request demand response resources. No environmental or regulatory restrictions are expected to impact reliability this winter. No other unusual operating conditions that could significantly impact reliability are expected for the upcoming winter.

Reliability Assessment

PJM evaluates its resources (generation, interchange and demand-side management) and demand to determine if the Reserve Margin requirements are met. Contingency analysis performed as part of the

Operation Analysis Task Force internal studies and the interregional studies with our neighbors ensures operations within secure transfer limits. The PJM projected (existing and prospective margins are the same) Reserve Margin for winter 2011-2012 is 51.8 percent based on total demand since Demand Response is used as a resource in this calculation. The projected Reserve Margin based on net demand, with Demand Response as a load reduction, is 56.7 percent. These levels are well in excess of the required Reserve Margin of 15.5 percent.[198] PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in ten years. PJM performs an annual LOLE study to determine the Reserve Margin required to satisfy this criterion. The study recognizes, among other factors, load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. The methods and modeling assumptions used in this study are available in PJM Manual 20.[199]

The latest resource adequacy study was completed in September 2010.[200] This study examined the period 2010 - 2021. The required Reserve Margins to satisfy an LOLE of one occurrence in ten years are summarized in Table I-2 on page 4 in the resource adequacy study report. With the integration of the ATSI portion of FirstEnergy, a relatively small increase in total forecast demand, an increase of demand-side management, a slight increase in net imports, new generation resources and the new Reserve Margin calculation technique (demand-side management as a resource), the PJM Reserve Margin has decreased by 1.3 percentage points over last year's but is still, by far, meets requirements. The PJM projected (existing and prospective margins are the same) Reserve Margin for winter 2011-2012 is 48 percent.

PJM has established rules/procedures to ensure fuel is conserved to maintain an adequate level of on-site fuel supplies under forecasted peak load conditions. PJM coordinates with neighboring entities and gas pipelines to address fuel issues in a timely manner. PJM has established rules/procedures to ensure fuel is conserved to maintain an adequate level on-site fuel supplies under forecasted peak load conditions. PJM coordinates with neighboring entities and gas pipelines to quickly address fuel issues. PJM has developed Reactive Transfer Interfaces to ensure sufficient dynamic MVAR reserve in load centers that rely on economic imports to serve load. PJM day-ahead and real-time Security Analysis ensure sufficient generation is scheduled / committed to control pre-/post-contingency voltages and voltage drop criteria within acceptable predetermined limits as outlined in M-3, section 3.[201]

Assessment Area Description

PJM[202] has 725 members that cover 168,500 Square Miles of Service Territory serving 58 million people in 13 States and Washington, DC. . PJM has 1,325 Generation Resources with Diverse Fuels. PJM is a Single Balancing Authority and is Summer Peaking. PJM exists in two NERC Regional Entity Organizations: RFC and SERC.

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198 http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/res-reports/20100120-forecasted-reserve-margin.ashx.

199 http://www.pjm.com/~/media/documents/manuals/m20.ashx.

200 http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2010-pjm-reserve-requirement-study.ashx.

201 http://www.pjm.com/~/media/documents/manuals/m03.ashx.

202 PJM is located at: http://www.pjm.com.

RFC

Executive Summary

All ReliabilityFirst Corporation (RFC) members, except Ohio Valley Electric Corporation (OVEC), are affiliated with either the Midwest Independent Transmission System Operator (MISO) or the PJM Interconnection (PJM) Regional Transmission Organization (RTO). OVEC, a generation and transmission company located in Indiana, Kentucky and Ohio, has arranged for Reliability Coordination (RC) service from MISO, but is not a MISO member company. Also, RFC does not have officially designated subregions. MISO and PJM each operate as a single Balancing Authority (BA) area. Since all RFC demand is in either MISO or PJM except for the small load (less than 100 MW) within the OVEC BA area, the reliability of PJM and MISO are assessed and the results used to indicate the reliability of the RFC Region.

The projection for the 2011/2012 PJM RTO winter peak is 130,711 MW, an increase of 15,965 MW, or 12.2 percent, higher than the projected 2010/2011 winter peak. The forecast is sharply higher because of the integration of the American Transmission Systems, Inc. (ATSI) portion of FirstEnergy, Cleveland Public Power (CPP), Duke Ohio and Duke Kentucky into PJM since last winter.

Last year's unrestricted non-coincident demand forecast for MISO of 93,836 MW is 12 percent higher than this year's unrestricted non-coincident demand forecast of 83,719 MW. This difference is mostly due to First Energy's exit from MISO effective June 2011. With an estimated 3,725 MW of demand diversity, the coincident MISO Total Internal Demand (TID) is 79,994 MW.

The forecast winter 2011/2012 coincident peak demand for the RFC region is 134,500 MW NID. This is 400 MW lower than the NID peak of 134,900 MW forecast for winter 2010/2011.

The total PJM generation resources expected to be in service during the 2011/2012 winter peak period is approximately 180,406 MW. PJM has contractually interruptible demand side management of 11,826 MW available to the PJM operators through May 31, 2012. With net transactions of 1,260 MW, this totals 193,492 MW of Existing resources that are considered to be *Existing-Certain*. PJM has added a total of 16,580 MW *Existing-Certain* resources since the 2010/2011 winter season. The generating resources of ATSI, Duke Ohio and Duke Kentucky are included in this assessment period.

MISO forecasts *Existing-Certain* capacity to be 107,420 MW for December of 2011, a 13 percent decrease compared to the prior year. The majority of this resource reduction is due to First Energy's departure from MISO. Net firm transactions are expected to be 3,087 MW.

The amount of OVEC, PJM and MISO net capacity resources in RFC is 213,700 MW. This is 3,100 MW less net capacity resources than the 216,800 MW that was reported within the 2010 winter assessment. Capacity resources committed to the markets at the beginning of the winter period are assumed constant throughout the winter. New capacity that is in-service after the start of the planning year (June 2011) is not included within the calculation of the winter Operating Reserve Margins for either PJM or MISO.

The PJM projected (existing and prospective margins are the same) Operating Reserve Margin for winter 2011/2012 is 48 percent (TID), with Demand Response (DR) included as a resource. This level is well in excess of the required Operating Reserve Margin of 15.5 percent.

MISO's current calculation of the winter 2011/2012 Operating Reserve Margin is 43.9 percent (TID), with DR included as a resource, which is higher than the 17.4 percent MISO system planning Operating Reserve Margin requirement.

Analyses were conducted by MISO and PJM to satisfy the RFC regional reliability standard which requires Planning Coordinators to determine the Operating Reserve Margin at which the Loss of Load Expectation (LOLE) is 0.1 day/year (a one day in ten years criterion on an annual basis) for their planning area.[203,204]

The assessment of PJM resource adequacy was based on reserve requirements determined from the PJM analysis. Similarly, the assessment of MISO resource adequacy was based on reserve requirements determined from the MISO analysis. Since PJM and MISO are projected to have sufficient resources to satisfy their respective Operating Reserve Margin requirements, the RFC region is projected to have adequate resources for the 2011/2012 winter period.

Many new additions to the bulk-power system since last winter are expected to be placed in-service within the ReliabilityFirst footprint. These system changes are expected to enhance reliability of the bulk-power system within ReliabilityFirst. Detailed information can be found in the PJM and MISO sections of this report.

There are no concerns in meeting target in-service dates of new transmission projects. PJM and MISO do not anticipate any significant transmission lines or transformers being out-of-service during the 2011/2012 winter season. No constraints are anticipated that could significantly impact reliability.

[203] BAL-502-RFC-02; See: http://www.nerc.com/page.php?cid=2|20.

[204] These analyses include demand forecast uncertainty, outage schedules, determination of transmission transfer capability, internal deliverability, other external emergency sources, treatment of operating reserves and other relevant factors when determining the probability of firm demand exceeding the available generating capacity.

SERC–E

Executive Summary

SERC-E (excludes utilities that are within the PJM reporting area) is a summer-peaking reporting area covering portions of two southeastern states (North Carolina and South Carolina). The five Balancing Authorities in this area are: Alcoa Power Generating, Inc – Yadkin Division, Duke Energy Carolinas, Progress Energy Carolinas, South Carolina Electric & Gas Company, and South Carolina Public Service Authority.

The 2011/2012 winter Total Internal Demand projection for utilities within the SERC-E reporting area is 42,459 MW, which is 826 MW (2 percent) higher than the projected 2010/2011 Total Internal Demand of 41,632 MW and 799 MW (1.9 percent) lower than the December 2010 winter peak of 43,258 MW. Entities experienced cooler than normal weather during the 2010/2011 winter season and took advantage of demand reduction techniques during that time. When comparing seasonal forecasts, both captured normal weather and a slowly recovering economy within the area. Companies within the SERC-E reporting area expect to have the following resources on peak during the period: *Existing-Certain* (53,180 MW), *Existing-Other* (3 MW), and Existing-Inoperable (106 MW) capacity. Since the prior winter season, 1,272 MW of *Existing-Certain* capacity has become operational. In addition, there are 400 MW of resources projected to be retired through the end of the assessment period. Other resources are expected to be in-service throughout the season.

Aggregate 2011/2012 winter Reserve Margins are 31.8 percent, indicating capacity resources in the area are adequate to supply the projected firm winter demand. The *Existing-Certain* and Net Firm Transaction, Prospective, and Deliverable winter-peak Reserve Margins for utilities in the area are projected to be 32.2, 31.8, and 31.8 percent, respectively. Entities within this area do not adhere to any regional/reporting area targets or Reserve Margin criteria. However, these margins are well above the 15 percent NERC Reference Marginal Level. Margins for the upcoming season continue to be based on load reductions due to the economy, generation availability, increased Demand-Side Management (DSM), and environmental compliance requirements. In order to address these concerns, companies will continue to monitor these risks in the future and make any necessary adjustments to their individual reserve target margins.

Since the 2010/2011 winter season, SERC-E entities have added a total of 180 miles of new transmission in service through the end of the upcoming winter season. In addition, three transformers are also expected to be installed or upgraded during this period. Entities are currently responding to NERC facility ratings recommendations, by determining facility ratings and modifying their processes to address concerns found with the results. Planned maintenance and construction scheduling will avoid removing significant transmissions lines or transformers from service during peak-demand periods. Reliability studies will be performed in the operating horizon to help minimize the impacts to the Bulk Electric System.

In conclusion, utilities in the area are not anticipating reliability concerns on the system for the upcoming season and are focused on maintaining reliability.

Demand

The 2011/2012 Total Internal Demand winter projections for utilities in the SERC-E reporting area (excluding utilities that are within the PJM reporting area) is forecasted to be 42,459 MW. This winter's forecast is 799 MW (1.9 percent) lower than the actual 2010/2011 winter peak demand of 43,258 MW and 826 MW (2 percent) higher than the 2010/2011 forecasted Total Internal Demand of 41,632 MW (Table 63). Entities report that the 2010/2011 winter season was colder than the 10-year normal average. Forecasts from last year and this year both predicted normal weather for the area and a slowly recovering economy. However, some entities in the area are adjusting their forecast upward to reflect growth in real income and manufacturing in the longer term.

Table 63: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**42,459**	**January-2012**
2010/2011 Forecast	41,632	December-2010
2010/2011 Actual	43,258	December-2010
All-Time Peak	43,258	December-2010

There are many sophisticated, industry-accepted methodologies that are used to develop load forecast for the area. Forecasts are developed by regressing demographics, economic scenarios, specific historical weather and demand assumptions, or the use of a Monte Carlo simulation using multiple years of historical weather. Entities continue to use vendors such as Economy.com and IHS Global Insight[205] for economic projections, and weather projections are taken from sources such as the National Oceanic and Atmospheric Administration[206] or individual company databases. Estimated demand and energy savings from future energy efficiency, and Demand Response programs are also accounted for in the forecast, as well as rate increase impacts and potential carbon legislation impacts. When appropriate, utilities adhere to their respective state commissions' regulations and/or internal business practices for determining their forecast and reserve requirements. In addition, the internal peak demands of individual entities are aggregated as a non-coincident peak value within the assessments for the period.

Utilities also have a variety of energy efficiency and Demand Response programs that are offered to customers in the area to help them manage electrical usage and reduce their costs.

Such programs include:

- Load control and curtailment programs
- Energy efficiency and products programs
- Standby generator controls
- Interruptible load programs and related rate structures
- Power Manager Power Share conservation programs[207]
- Residential Energy Star appliance programs
- General service and industrial time-of-use rates.

[205] www.**ihs**.com
[206] www.**noaa**.gov/
[207] www.duke-energy.com

Generally, these programs are used to reduce the affects of seasonal peaks and are considered part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event.

Demand Response is projected to be 3.3 percent of Total Internal Demand. This percentage is projected to reduce peak demand on entity systems within the area.

Measurement and Verification (M&V) for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and firm load requirements. Effectiveness is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule.

Forecast uncertainty is addressed in various ways within the area. As stated above, entities take into account economic inputs, historical weather (normal/extreme) conditions, energy use (residential and commercial), and demographics. Entities continue to evaluate these model inputs and track the actual parameters with forecast predictions. Forecasts are based on an assessment of historical events that occurred over the last 30 years, as well as assumptions regarding the future. Recent modifications to the forecast account for variables in weather conditions over the last 10 years. Economic inputs are considered from consulting firms such as Moody's, Economy.Com or the responses of system energy to changes in gross domestic products (GDP). Projections of peak demand developed for the winter season are based on a weather adjustment process, total energy requirements and long-term peak demand at various levels of uncertainty for a period. In addition to the peak-demand base-case forecast, high and low-range scenarios are developed to address uncertainties regarding the future and extreme weather conditions. Representations of historical peak demand data within the models are modified to reflect the various scenarios of extreme summer and winter conditions in the future. Adjustments are also made to capture peaks experienced and new information as it is made available. However, no major changes have been made to reflect the existing economic conditions.

Generation

The expected aggregate capacity on-peak of the companies within the SERC-E reporting area are shown below (Table 64). This capacity is projected to meet demand during this time period. Entities within the area include renewables in their portfolio to meet the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) of North Carolina. Under this standard, investor-owned utilities in North Carolina will be required to meet up to 12.5 percent of their energy needs through renewable energy resources or energy-efficiency measures. Rural electric cooperatives and municipal electric suppliers are subject to a 10 percent REPS requirement.[208] Variable resources are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the standard and maintaining the flexibility to make long-term resource decisions. Companies in this area have not reported any wind capacity for the 2011/2012 winter.

[208] http://www.ncuc.commerce.state.nc.us/reps/reps.htm; and http://www.epa.gov/statelocalclimate/state/tracking/individual/nc.html.

Table 64: SERC-E Winter Capacity Breakdown

Capacity Type	2011/2012 Winter (MW)
Existing-Certain	53,180
Nuclear	11,824
Hydro/Pumped Storage	6,068
Coal	19,274
Oil/Gas/Dual Fuel	15,714
Other/Unknown	300
Solar	16
Biomass	74
Wind	0
Existing-Other	3
Existing-Inoperable	106
Future-Planned	-201

As of the end of September 2011, the seasonal drought outlook for South Carolina, summarized from information provided by the South Carolina State Climatology Office[209], indicates that the entire state drought status is rated as 'moderate.' The status level is driven by continuing concern over agricultural impacts, low stream flows and increased forest fire activity. Sporadic and localized rainfall has not mitigated the ongoing drought status throughout the state. Similarly, drought conditions are expected to persist or intensify in the Piedmont regions of North and South Carolina. The National Oceanic and Atmospheric Administration's (NOAA) U.S. Seasonal Drought Outlook[210] through December 31, 2011, anticipates that the majority of South Carolina's drought, while ongoing, may improve. Entities are anticipating reservoir levels to be sufficient to meet peak demand and daily energy demand throughout the forecasted winter season if normal rainfall occurs, and will continue to monitor the situation closely.

Approximately 400 MW of reduced generation is expected during the winter due to unit retirements. However, new generation capacity scheduled to come on-line this fall will offset planned retirements for the winter season. Overall, there are no known or projected significant conditions or generator outages that would reduce capacity in the area.

Capacity Transactions

Utilities within the SERC-E reporting area reported the imports and exports listed below (Table 65) for the upcoming winter. These transactions include both external and internal transactions to the region and the reporting area. The majority of the purchases are backed by firm contracts for both generation and transmission and are not considered to be based on partial path reservations. However, one entity's 155 MW purchase agreement is considered "make-whole" as defined by FERC in Order No. 890.[211]

Entities do not rely on resources outside the area or region for emergency imports, reserve sharing or outside assistance/external resources.

[209] http://www.dnr.sc.gov/climate/sco/Drought/drought_current_info.php.
[210] http://www.cpc.ncep.noaa.gov/products/expert_assessment/season_drought.gif.
[211] http://www.ferc.gov/whats-new/comm-meet/2007/122007/E-1.pdf.

Collectively, members of the VACAR Reserve Sharing Agreement (RSA) hold 1.5 times the largest single contingency (1,135 MW) in the VACAR RSA area to meet operating reserve requirements. The Reserve Sharing Group is expected to have adequate reserves throughout the 2011/2012 winter operating period.

Table 65: On-Peak Capacity Transactions

	Transaction Type	Winter 2011/2012 (MW)
Imports	Firm	1,880
	Expected	-
	Non-Firm	-
	Total	**1,880**
Exports	Firm	750
	Expected	-
	Non-Firm	-
	Total	**750**
	Net Transactions	**1,130**

Transmission

Several improvements to transmission lines and transformers for the coming winter are show below (Table 66 and Table 67). Entities have responded to NERC facility ratings recommendations by verifying facility ratings and modifying their processes to address concerns found (if any) with the ratings of the lines. Should an analysis indicate that a transmission line's rating is lower than documented; the line will either be opened until repairs can be made to restore it to its design rating, or it will be de-rated. Reliability studies will be performed and verification processes will be scheduled to minimize the impact to the Bulk Electric System. In addition, planned maintenance and construction schedules are arranged to avoid removing significant transmission lines or transformers from service during peak-demand periods. One transformer is expected to be placed into service during the assessment period. No new significant substation equipment is anticipated to be placed in-service prior to the 2011/2012 winter. Entities continue to consider new technologies as needed to meet system performance requirements.

Table 66: SERC-E Expected Transmission Enhancements

Project Name	Status	Projected In-Service Date	Voltage (kV)
Asheville-Enka 1	Complete	12/1/2010	230
Pepperhill-Robert Bosch 1	Complete	5/24/2011	115
Pleasant Garden (Duke)-Asheboro (Progress) 1	Complete	5/30/2011	230
Rockingham-West End 2	Complete	5/30/2011	230
Asheboro-Pleasant Garden 1	Complete	5/30/2011	230
Denny Terrace-Pineland 1	Complete	6/2/2011	230
Richmond-Ft. Bragg Woodruff St 1	Under Construction	12/1/2011	230
Robert Bosch Tap-Robert Bosch 1	Planned	12/31/2012	115

Table 67: SERC-E Transformer Additions

Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	Projected In-Service Date	Description	Status
Enka 230 kV Substation	230	115	12/1/2010	Installed 1-300 MVA 230/115 kV transformer at existing 115 kV substation	Complete
Asheboro 230 kV	230	115	2/18/2011	Replaced two existing 200 MVA Transformers with 300 MVA transformers	Complete
Ritter 230/115kV	230	115	2/22/2011	Construction of 336MVA Substation	Complete
Mt. Olive	230	115	12/1/2011	Installing 1-200MVA 230/115 kV Transformer	Complete

Currently, there are no concerns with meeting in-service dates. New construction efforts are focused on completing facilities ahead of seasonal peak periods. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during higher seasonal load periods. Additionally, no significant transmission facilities are anticipated to be out of service during the winter months.

There are no anticipated transmission constraints identified that significantly impact reliability during the winter assessment period. Regional studies are performed on a routine basis. Coordinated single transfer capability studies with external utilities are performed quarterly through the SERC Near-Term Study Group (NTSG). Projected seasonal import and export capabilities are consistent with those identified in this assessment.

Operational Issues

Most area utilities participate in Reserve Sharing Agreements (RSA) with other VACAR utilities. Membership within this group helps to support Reserve Margins and recovery efforts from extreme events. No operational problems or constraints are anticipated during the assessment period. Reserve Margins are planned such that the loss of multiple units can be accommodated without threatening reliability.

As mentioned above, many entities in the area participate in various coordinated study groups. Preliminary results for the NTSG's winter peak study will be completed by mid November 2011. This study is done on a seasonal basis to evaluate the performance of the system. The most current information is used to model system configurations and peak load. Outside of the regular seasonal studies, entities have not identified the need for special operating studies for the winter.

Since both the amounts of distributed and variable generation are limited in the area and entities hold a diverse amount of resources, special operating procedures are not needed for the integration of variable resources, or minimum demand conditions. Entities also report that there are no identified concerns with meeting peak demands by calling on Demand Response resources. There are also no restrictions on the number of times that emergency Demand Response actions can be employed and are readily available as needed.

Currently, entities in the area are not aware of any environmental and/or regulatory restrictions that could impact reliability during winter 2011/2012. Lake levels are carefully managed, to the extent weather conditions and inflows permit, in order to mitigate hydro capacity limitations during seasonal peak load periods.

As previously stated, seasonal operating studies have not identified any reliability concerns from projected operating conditions. No unusual operating conditions are anticipated for the upcoming winter. Entities will continue efforts to monitor the system through studies, assessing line ratings and improving the system to minimize negative impacts on the system that could affect reliability for the winter.

Reliability Assessment

Utilities within the SERC-E reporting area perform stability, dynamics, transmission, operational, and resource adequacy studies to monitor the system and manage their future resource needs. These studies are performed on a seasonal, daily or quarterly basis to ensure that resources are secured to meet demand.

The existing, anticipated and prospective winter-peak Reserve Margins for utilities in the reporting area are projected to be 32.2, 31.8, and 31.8 percent, respectively. Utilities within this area do not adhere to any regional/reporting area targets or Reserve Margin criteria. However, some utilities adhere to North Carolina Utilities Commission (NCUC) regulations. Other utilities established individual target margin levels to benchmark margins that will meet the needs for peak demand. Assumptions used to establish the individual utilities' reserve/target margin criteria or resource adequacy levels are based on prevailing expectations of reasonable lead times for the development of new generation, procurement of purchased capacity, siting of transmission facilities, and other historical experiences that are sufficient to provide reliable power supplies. Other assumptions include levels of potential DSM activations, scheduled maintenance, environmental retrofit equipment, environmental compliance requirements, purchased power availability, and peak-demand transmission capability/availability.

Risks that would have negative impacts on reliability are also an important part of the process to establish assumptions. Some of these risks would include significant amounts of renewable resources, increases in energy-efficiency/DSM programs, extended base-load capacity lead times (for example, coal and nuclear), environmental pressures, and derating of units caused by extreme hot weather/drought conditions. In order to address these concerns, companies continue to monitor these future risks and make any necessary adjustments to the Reserve Margin target in future plans.

Resource adequacy studies are used to recognize load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed annually using inputs provided from Generator Operators. As conditions warrant, entities may see the need to perform additional assessments to mitigate challenging conditions on the system. Entities report that the latest studies project Reserve Margins to be in the range of 17 to 44 percent based on the current forecast, purchased capacity, generation and DSM resources for the upcoming winter. These margins are more than adequate to meet the needs of the system during this period.

The projected aggregate Reserve Margin for entities within the area is 31.8 percent compared to last winter's projection of 29.1 percent. Although there are insignificant changes between the 2010/2011 and 2011/2012 margins, entities report that they experienced extremely cold weather during the 2010/2011 winter. This decrease in temperatures produced lower margins and higher peak demands than forecasted. However, margins for the upcoming season continue to be based on load reductions due to the economy, increased DSM, significant increases in generation, and mild weather. It is anticipated that capacity in the area should be adequate to supply forecast demand.

Fuel supply or delivery problems are not anticipated for the period. Some utilities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to communicate near- and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are conducted to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuels, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations for some units. This is considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

Both static and dynamics assessments of reactive power are performed and produced on an individual company basis within the SERC-E reporting area. Entities primarily rely on evaluations of summer conditions/studies when the system is the most stressed to ensure there is sufficient reactive power support for the system during winter peaking conditions. Most entities in this reporting area participate in the SERC Dynamics Review Subcommittee (DRS) assessment of annual dynamic conditions on the system. The majority of the studies for the upcoming season do not show any significant issues that might impact reliability. Several other studies such as a capacitor optimization study, a 2010 summer northern region dynamic load limit study, and generator scenarios have been performed to ensure sufficient dynamic and static reactive resources are available to meet transmission planning (TPL) standard requirements for the operating horizon. Similarly, another dynamic study was recently performed in the western area of North Carolina, which included similar dynamic simulations, including modeling the dynamic effects of induction motor loads. The above studies were performed this summer in preparation for the upcoming season and indicate that adequate reactive reserves exist for the upcoming 2011/2012 winter peak load.

Other Area-Specific Issues

To minimize reliability concerns on the system, entities regularly study and review annual and seasonal assessments. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Entities are also active participants within the SERC NTSG, which regularly performs annual reliability studies for summer and winter peak conditions as well as quarterly OASIS studies for summer, fall, winter, and spring conditions. No unique operational problems were observed or are anticipated for the 2011/2012 winter.

Transmission maintenance schedules are carefully reviewed and evaluated to insure reliability concerns are addressed, and to permit as much prioritized maintenance as can be accommodated prior to seasonal peak periods. Likewise, new construction efforts are focused on completing facilities ahead of seasonal peak periods. Annual planning activities continue to address both near- and long-term facility needs.

Assessment Area Description

SERC-E is a summer-peaking reporting area covering portions of two southeastern states (North Carolina and South Carolina.) with a population of approximately 13.9 million.[212] Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 58,900 square miles. There are five Balancing Authorities in SERC-E: Alcoa Power Generating, Inc – Yadkin Division, Duke Energy Carolinas, Progress Energy Carolinas, South Carolina Electric & Gas Company, and South Carolina Public Service Authority.

[212] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population.

SERC–N

Executive Summary

SERC-N is a summer-peaking reporting area covering five southeastern states (Tennessee, Alabama, Georgia, Kentucky, and Mississippi.). This area consists of six Balancing Authorities: Associated Electric Cooperative, Inc., Batesville Balancing Authority, East Kentucky Power Cooperative, Electric Energy, Inc., LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company, and Tennessee Valley Authority.

Entities within the SERC-N reporting area project a Total Internal Demand of 47,123 MW for the 2011/2012 winter season, which is 129 MW (0.3 percent) higher than the projected 2010/2011 Total Internal Demand of 46,994 MW, and 2,127 MW (4.7 percent) higher than the December 2010 winter peak of 44,996 MW. Entities identified no significant differences in the projections and forecasts continue to account for slowed economic growth affecting the region and the U.S. The following resources are expected to be on peak for the upcoming season: *Existing-Certain* (57,795 MW), *Existing-Other* (731 MW), and Existing-Inoperable (878 MW). *Existing-Certain* capacity has increased by 1,325 MW since the last winter season. There are no Future resources projected to be in service through the end of the assessment period. In addition, entities are not anticipating significant capacity additions or retirements.

The SERC-N utility *Existing-Certain* and Net Firm Transaction, and Anticipated aggregate winter-peak Reserve Margins are both projected to be 25.3 percent. The Deliverable Capacity Reserve Margin for this area is also 25.3 percent. There are no regional/reporting area targets or Reserve Margin criteria for SERC-N, however the reported margins are well above the 15 percent NERC Reference Marginal Level. Limited changes in forecast show that the economy continues to be a significant concern within the area. Entity processes continue to capture modest growth in customer demand, derates (from planned maintenance and economic conditions) and various system improvements that ensure reliability. Overall, utilities in the area will minimize reliability concerns through ongoing system planning processes and industry lessons learned.

Approximately 92 miles of new transmission have been added to the system in this area since the prior winter season. In addition, four transformer projects are expected to be put into service by the end of the assessment period. No transmission reliability concerns are expected to significantly impact Bulk Electric System reliability for the winter season. Several entities are compensating for planning maintenance outages by the use of system studies, operating guides and purchases to address their system issues during the winter outage periods. Entities will continue to evaluate the transmission system to identify any future constraints and mitigate concerns that could significantly impact reliability in the future.

Utility operational planning studies take into consideration weather, demand, and unit availability, which help to address any inadequacies and mitigate risks. Based on the results of these studies, entities do not anticipate operational problems for the period.

Demand

Projected Total Internal Demand for utilities in the SERC-N reporting area for the upcoming winter is 47,123 MW. The projected Total Internal Demand is 2,217 MW (4.7 percent) higher than the actual 2010 winter peak of 44,966 MW and 129 MW (0.3 percent) higher than the 2010/2011 forecasted Total Internal Demand of 46,994 MW (Table 68). The internal peak demands of individual entities are aggregated as a non-coincident peak value. There are no significant differences between last year's winter demand forecast versus this year's projections. Forecasts continue to show limited growth in the economies of the region and the U.S.

Table 68: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**47,123**	**January-2012**
2010/2011 Forecast	42,779	January-2011
2010/2011 Actual	44,996	December-2010
All-Time Peak	46,819	January-2009

The 2011/2012 winter demand forecast is based on normal weather conditions and expected economic data for the area's population, expected demographic, employment, energy exports, and gross regional product increases and decreases. It also considers economic data from national and regional levels. Secondary forecasts are developed for extreme weather conditions and for optimistic and pessimistic economic scenarios. These forecasts also consider the current state of the economies within the region and the U.S.

The primary sources of Demand Response for utilities within the reporting area are the Direct Load Control (DLC) program and the interruptible product portfolio. DLC includes a program with contracts for interruptible load and verified by a third party. Through this program, companies have contractually agreed to reduce their loads within minutes of a request. DLC operational planning takes into account an estimate of the amount of load available and is not a sum of total load under contract. Other Demand Response products that utilize control devices are also used by entities within the area on air conditioning units and/or water heaters in residences and distributor-operated voltage regulation programs. Entities are planning for increased demand reductions from these programs.

Modeling & Verification (M&V) of Demand Response programs are also achieved through independent analysis by a third-party M&V contractor of: near-real time metering (tracking actual responses to an event), after-the-fact time-differentiated billing data, event feedback from homes and business under DLC, and individual feeder data from distributor-operated voltage regulation. Other entities test residential and commercial load-control programs for operational functionality each spring. This analysis of load profiles allows for verification of demand reduction. Although most of the programs mentioned are designed for summer operation only, Demand Response is projected to be 2.8 percent of Total Internal Demand for the upcoming winter. This percentage is expected to reduce peak demand on entity systems.

The following energy-efficiency programs and various advanced lighting and third-party M&V groups are currently operating within the area for residential and commercial customers:

- Customer cost-saving energy surveys and audit evaluations
- Customer education
- Responsive pricing
- Residential/commercial/industrial conservation
- Electric thermal storage incentives
- New construction (heat pump and geothermal)
- Energy manufactured homes
- Air-source heat-pump programs (replacing resistance heat 10 years or older)
- Low-income weatherization
- Low-income assistance
- HVAC system improvements
- Industrial compressed-air programs.

Commercial/industrial/direct-served industry consumers have programs targeted to focus on efficiency improvements in HVAC, lighting, motors and controls, and other electrical-intensive equipment. For M&V within these programs, entities reported that they may use third-party evaluators to review the performance of all programs on an ongoing basis to assure the programs continue to achieve the projected levels of energy and peak demand reductions. Some entities reported that programs must pass a quantitative and a qualitative screening assessment to focus on customer acceptance, reliability, and cost effectiveness. LG&E/KU LSE filed a request[213] with the Kentucky Public Service Commission for three new programs and enhancement to five existing programs. Additionally, TVA published a new Integrated Resource Plan that includes a goal of achieving 3.5 percent of sales in energy-efficiency savings by 2015.[214]

Entities use a variety of techniques to assess the variability in projected demand, based on the projections of weather, the economy, electric prices, industrial growth variables and demographics. One method used to accomplish this is to analyze on an annual basis, the relationship between seasonal peak loads and temperature during and leading up to the time of the peak. Other utilities may use forecasts assuming normal weather, and then develop models for milder conditions based on historical peaks. They would then use demand models to predict variances.[215] These short- and long-term models reflect optimistic and pessimistic conditions that include scenarios that model extreme differences in economic and weather conditions. No significant changes have been made to the demand forecasting methods since the previous forecast.

Generation

Capacity within the SERC-N reporting area is shown for the categories of Existing- (Certain, Other, and Inoperable) and Future (Planned and Other) capacity below (Table 69). Variable resources are limited

[213] http://psc.ky.gov/Home/Library?type=Cases&folder=2011 cases/2011-00134.

[214] http://www.tva.gov/environment/reports/irp/pdf/Final_IRP_complete.pdf.

[215] For the majority of the load in the area, peak information is developed as a coincident value for the reporting area-wide model and as non-coincident values for each distribution delivery point. Models are developed every two years, with updates made to the forecasts annually, weekly or daily.

within this area, although there are some purchases sourced from wind that are included in the transfer amount, and a small amount of solar supply that is part of a customer-owned generation buy-back program. There are 152 MW (nameplate) of wind resources located inside the SERC-N reporting area. The capacity values of wind contracts are usually based on the applicable contract terms. In large part, the assumed contribution at the time of the system peak is computed by applying a 12 percent capacity credit factor to the nameplate ratings of the associated wind generators. This 12 percent factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area. The contribution from the customer-owned solar resources is based on the solar insolation[216] values for the TVA area at the time of the winter peak. TVA is continuing to evaluate these and other renewable resources as part of its integrated resource planning process.

Table 69: SERC-N Winter Capacity Breakdown

Capacity Type	2011/2012 Winter (MW)
Existing-Certain	57,795
Nuclear	6,874
Hydro/Pumped Storage	6,125
Coal	28,183
Oil/Gas/Dual Fuel	16,564
Other/Unknown	50
Solar	0
Biomass	17
Wind	20
Existing-Other	724
Existing-Inoperable	878
Future-Planned	0

Although many southern states are experiencing 'extreme' to 'severe' drought conditions, according to the U.S. Drought Monitor Map as of August 23, 2011[217], the SERC-N reporting area is only considered 'abnormally' dry. Similarly, the Palmer Hydrological Drought Index[218] of long-term conditions is consistent in summarizing the area to be moist, with some dry conditions. Reservoir levels and river flow are not expected to change in a way that would materially affect hydro capacity relative to planning assumptions of the entities in the area. Overall, the SERC-N reporting area anticipates near normal precipitation for 2011/2012 winter through 2012 spring.

Although entities do source gas fuel supply from the Gulf of Mexico that can be impacted during severe weather, the use of storage, (segregated in two storage facilities) shale gas supply, backhauls and supplier-delivered gas should be sufficient to meet generation needs. Fuel levels (gas, coal, oil) for utilities within the reporting area are not a concern for the winter. Emergency procedures, alternative delivery routes, and diversified vendor portfolios are in place to address a variety of issues relating to fuel supply or extreme weather.

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[216] Insolation is a measure of solar radiation energy received on a given surface area in a given time.

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

[218] http://www.ncdc.noaa.gov/oa/climate/research/prelim/drought/phdiimage.html.

Approximately, 890 MW is expected to be out of service during the 2011/2012 winter season due to planned outages related to maintenance and expected forecast conditions. Entities have accounted for this capacity in their generation plans and will encounter no impact to overall reliability. Additional short-term market purchases will be made if necessary.

Capacity Transactions

Utilities within the SERC-N reporting area reported the following imports and exports for the 2011/2012 winter (Table 70). These imports have been included in the aggregate Reserve Margin for utilities in the area. The majority of these imports and exports are backed by firm contracts for both transmission and generation, with no partial path reservations. There are no reports of import or export contracts that are categorized as make-whole Liquidated Damage Contracts (LDC).

Table 70: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	1,068
	Expected	-
	Non-Firm	854
	Total	**1,922**
Exports	Firm	1,462
	Expected	-
	Non-Firm	52
	Total	**1,514**
Net Transactions		**408**

Contingency reserves and emergency imports are obtained from a variety of resources such as the TVA-East Kentucky Power Cooperative-E.ON (or TEE) Contingency Reserve Sharing Group (TCRSG) and the Southwest Power Pool (SPP) RSA. The TCRSG consists of three Balancing Authorities that are internal to the area and is intended to provide an immediate response to contingencies. This enables the group to comply with DCS standard and assists in preventing the curtailment of native load. Even though some entities rely on internal/external resources for imports, there are some companies within the area that do not depend on short-term outside purchases or transfers from other regions or reporting areas to meet demand requirements. Total emergency MWs from these imports were not reported, but are available as needed.

Transmission

New Bulk Electric System transmission facilities (transmission lines, transformers, and substation equipment) since last winter that are projected to be in service for the upcoming winter are shown below (Table 71 and Table 72). No reliability concerns regarding project in-service dates have been identified. With the exception of a new 500 kV transformer bank at Jackson, entities have not installed new significant substation equipment since last winter, but anticipate adding some in the next several years (ex: smart grid equipment and SCADA upgrades.). These technologies will continue to be evaluated and considered for improvement projects for Bulk Power System reliability.

Table 71: SERC-N Expected Transmission

Project Name	Status	Projected In-Service Date	Voltage (kV)
Long Lane-Phillipsburg 1	Complete	12/31/2010	100
Middletown-Collins 1	Complete	1/12/2011	138
Chouteau Plant-Sportsman Acres 1	Complete	2/2/2011	161
GRDA-Sportsman Acres 1	Complete	2/2/2011	345
Mansfield-Mtn. Grove	Complete	6/2/2011	161
Camp Clark-Lamar	Complete	06/02/2011	161
Fredericktown-Fredericktown Tap	Complete	7/1/2011	161

Table 72: SERC-N Transformer Additions

Project Name	Voltage		Projected In-Service Date	Description	Status
	High-Side (kV)	Low-Side (kV)			
Jackson, TN	500	161	6/1/2011	Install three single phase 500-161 kV transformers	Complete
Guntersville, AL	161	115	9/2/2011	Install four, single phase 161-115-11.5 kV transformers	Complete
Guntersville, AL	161	115	9/2/2011	Retire six, single phase 154-115-11.5 kV transformers	Complete

Although many of the entities in the area are not expecting significant facilities to be out-of-service, planned maintenance of several generating units will need to be coordinated. Several entities are managing these outages by the use of system studies, operating guides and purchases to address their system issues during the outage periods. Entities will continue to evaluate the transmission system to identify any future constraints and mitigate concerns that could significantly impact reliability in the future. Interregional transmission transfer capabilities for the upcoming winter are being developed, and preliminary results indicate that there are no significant issues that will impact Bulk Power System reliability.

Operational Issues

Many entities within the reporting area perform routine operating studies (bi-annual load forecast; monthly, weekly, and daily operational planning efforts; annual assessment of winter peak and temperature, etc.) to assess the system. These studies take into consideration weather, demand, and unit availability. This helps to address any inadequacies and mitigate their risks. Based on the results of these studies, entities do not anticipate operational problems.

The majority of the entities have not included variable resources as firm capacity on their systems, with the exception of TVA, which has contracted for up to 966 MW of wind power during the first quarter of 2012. Entities are not anticipating operational changes or concerns due to integration of variable resource contracts for the winter assessment period. Variable resources can be curtailed for reasons of system reliability (line loading relief and minimum generation limits). In addition, there are limited concerns resulting from minimum demand and/or over-generation. System operators in the area have the authority to take units off-line during real-time conditions to address minimum generation issues while maintaining system reliability.

Reliability concerns associated with Demand Response resources are not a concern for this winter due to limited Demand Response within the area. Entities report that there are no environmental or regulatory restrictions, or other unusual operating conditions anticipated that would significantly impact reliability. While the TVA system experienced significant damage from multiple tornados on April 27, 2011, all repairs were completed and the system was fully restored by mid-July. Severe winter weather conditions (ice storms and heavy snowstorms) are always potentially threatening to areas of the system if they materialize. Weather patterns are monitored closely and emergency restoration plans are activated, if needed.

Reliability Assessment

Numerous assessments are performed throughout the area to assess reliability. Utilities within the SERC-N reporting area perform many stability, dynamics, transmission, operational, and resource adequacy studies to monitor the system and manage their future resource needs. These studies are done on a seasonal, daily or quarterly basis to ensure that resources are secured to meet demand.

The existing, anticipated and prospective winter-peak Reserve Margins (as reported in August 2011) for utilities within the SERC-N reporting area are projected to be 25.3 percent for all margin categories. Margins are higher when compared to last year's 21.5 percent for SERC-N. Entities within this reporting area do not have any regional/reporting area targets or Reserve Margin criteria to adhere to, but some individual entity criteria are established. These are based on the Balancing Authority's criteria such as most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, and loss-of-load probability studies (such as 1 day/10 years). This target (optimal) Reserve Margin is then adjusted to reduce risks and enhance reliability beyond minimum levels to produce the final level of planning reserves that are used for study purposes. Entities continue to implement new study capabilities and detailed probabilistic assessments into their annual planning processes.

In order to ensure fuel delivery, the practice of having a diverse portfolio of suppliers is common within the reporting area. Entity fuel departments typically monitor supply conditions on a daily basis through review of receipts and coal burns, and interact daily with both coal and transportation suppliers to review situations and foreseeable interruptions. Any identifiable interruptions are assessed with regard to current and desired inventory levels. By purchasing from different regions, coal is projected to move upstream and downstream to various plants. Some plants have the ability to re-route deliveries among themselves, and some stations that have coal delivered by rail can also use trucks to supplement deliveries. Utilities have reported that they maintain fuel reserve targets greater than 30 days of on-site coal inventory. Fuel supplies are reported to be adequate and readily available for the upcoming winter.

Entities maintain very close relationships with gas pipelines and producers that serve their gas power plants. These communications can help to reschedule deliveries, move deliveries from one location to another, or move the origin of the coal/oil to access different modes of transportation. This is an example of how close relationships are beneficial to ensure adequate fuel supplies are on hand to meet load requirements. In the event of a potential supply or transportation disruption, entity processes allow the engagement of stakeholders. Coal and gas service plans are provided to manage the situation. Planned unit maintenance outages or de-rates may be delayed or cancelled.

Static and dynamic studies of reactive power are performed by utilities on an individual basis and within regional study groups [SERC Dynamics Study Group (DSG), Eastern Interconnection Reliability Assessment Group MRO-FRC-SERC West-SPP (ERAG MRSWS), SPP Transmission Expansion Plan/Integrated Transmission Planning (STEP/ITP), SERC Long-Term Study Group (LTSG), etc]. Some utilities continue to follow their criteria to address voltage stability in the area and verify system stability margins. Other utilities use engineering analysis, such as P-V and Q-V analysis, to monitor reliability. All companies are working to meet the generating unit reactive (static) testing requirements as described in the NERC Standards (MOD-025-1, etc.). Currently, there are no reactive power-limited areas on the Bulk Electric System that will impact reliability during the period. Operating guides are in place to address existing issues found in previous studies.

Other Area-Specific Issues

Entities continue to minimize reliability concerns through ongoing operational planning/longer-term planning processes. Industry events are also monitored for potential lessons learned.

Assessment Area Description

SERC-N is a summer-peaking reporting area covering portions of five southeastern states (Tennessee, Alabama, Georgia, Kentucky, and Mississippi.) with a population of approximately 27.6 million[219]. Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 101,000 square miles. There are six Balancing Authorities in SERC-N: Associated Electric Cooperative, Inc., Batesville Balancing Authority, East Kentucky Power Cooperative, Electric Energy, Inc., LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company, and Tennessee Valley Authority.

[219] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population.

SERC–SE

Executive Summary

SERC-SE is a summer-peaking reporting area covering portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida). This reporting area consists of four Balancing Authorities: PowerSouth Energy Cooperative, South Mississippi Electric Power Association, Southeastern Power Administration, and Southern Company Services, Inc.

The 2011/2012 winter projected Total Internal Demand for the utilities in SERC-SE is 44,259 MW which is 1,785 MW (4.2 percent) higher than the projected 2010/2011 Total Internal Demand of 42,473 MW and 3,503 MW (7.3 percent) lower than the December 2010 winter peak of 47,762 MW. Entities experienced much cooler temperatures during the 2010/2011 winter months. Forecast models in the area have been updated to better reflect current economic conditions, primarily in commercial and residential markets. The following capacity is predicted to be available in the area during the winter peak: *Existing-Certain* (64,857 MW), Existing Other (2,727 MW), and Existing Inoperable (0 MW). *Existing-Certain* capacity has increased by 488 MW since last winter season. There are no Future resources or significant changes in capacity projected for the end of the assessment period. If needed, outages will be met with other generating resources available within entity portfolios.

Aggregate 2011/2012 winter Reserve Margins are 55 percent. *Existing-Certain* and Net Firm Transaction, Anticipated and Deliverable winter peak Reserve Margins are projected to be 55, 55, and 60.6 percent, respectively. These margins indicate that utility capacity resources are adequate to supply the area's firm winter demand. The utilities in the SERC-SE reporting area do not adhere to any regional/reporting area targets or Reserve Margin criteria. However, most utilities do use a reference marginal level of 15 percent and indicate that projected Reserve Margins remain well above this target. Entities are working to improve and update projections from weather, economics, and demographics in their models and assessments that take into account historical peaks and various conditions that affect the system. As economic conditions and generation mixes change in the area, these models and studies will capture the trends as they occur.

Approximately 54 miles of new transmission have been added to the system in this area since the prior winter season. In addition, 13 transformer projects are expected to be put into service by the end of the assessment period. No transmission reliability concerns are expected to significantly impact Bulk Electric System reliability for the winter season. To minimize impacts on the system, utilities within the reporting area annually develop assessments of the transmission system. If constraints occur, mitigation procedures are in place to relieve them.

The following are the most common challenging operational issues: loop flows, congestion, potential effects of climate legislations, and real-time transmission loading issues. Entities have found that the availability of large amounts of excess generation in the area has resulted in fairly volatile day-to-day scheduling patterns and exacerbate transmission loading concerns. These operational issues are not reliability concerns, but market issues.

As transmission constraints are identified through studies, they will be mitigated as needed to minimize reliability concerns on the Bulk Power System. In addition, companies within the SERC-SE reporting area are also monitoring and studying the potential reliability impacts of potential climate legislation (specifically the U.S. Environmental Protection Agency's Maximum Achievable Control Technology [MACT] rules) on the Bulk Power System. Fossil generating units in the Southern Balancing Authority are currently being evaluated for the appropriate federal and state regulations related to air and/or water quality. Overall, no existing conditions are projected to impact the reliability on the Bulk Power System for the upcoming winter season.

Demand

Utilities within the SERC-SE reporting area aggregately reported 44,259 MW of Total Internal Demand for the 2011/2012 winter season. The upcoming winter season forecast is 3,503 MW (7.3 percent) lower than the actual 2010/2011 winter peak demand of 47,762 MW and 1,785 MW (4.2 percent) higher than the 2010/2011 winter forecasted Total Internal Demand of 42,473 (Table 73). The internal peak demands of individual entities are aggregated as non-coincident peak values, and resource evaluations are normally based on summer peaking conditions. Entities experienced much cooler temperatures then expected during the 2010/2011 winter months. Since then, peak demand models have been updated to better reflect current conditions. Economic forecasts have been revised primarily in commercial and residential markets. However, the projected weather normal winter demands are relatively unchanged from last year.

Table 73: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**44,259**	**January-2012**
2010/2011 Forecast	42,473	January-2011
2010/2011 Actual	47,762	December-2010
All-Time Peak	48,742	January-2010

Similar to other SERC reporting areas, utilities evaluate load predictions based on economic and normal weather conditions, as determined by historical system-average weather data. Normal weather may be calculated based on weighted averages of weather data points throughout the service territory or through Monte Carlo simulation of historical data. Economic determinations may be accomplished through econometric time-series analysis or vendor projections (Economy.com[220] or IHS Global Insight[221]). Projections may also factor in fluctuations in demographics and the effects of energy efficiency and Demand Response programs. When appropriate, utilities adhere to their respective state commissions' regulations and internal business practices for determining their forecast and reserve requirements.

Demand Response programs within the area consist of programs ranging from customer stand-by generation, real-time pricing/critical-peak pricing (reducing energy use based on price signaling) and interruptible demand programs (requesting customers to reduce energy use) to DLC programs (energy

[220] http://www.economy.com/default.asp.
[221] http://www.ihs.com/products/global-insight/.

provider curtailing customer energy use). These programs allow entities within the reporting area to have better ability to control various amounts of load when needed for reliability purposes.

One example of a Demand Response program is the H2O Plus program,[222] which utilizes the storage capacity of electric water heaters. This program allows entities within the SERC-SE reporting area to install load control devices that can be activated during peak periods, which results in the following benefits:

- Help reduce the need to build or purchase capacity.
- Respond to volatile wholesale energy markets.
- Improve the efficiency (load factor) as well as the utilization of generation, transmission, and distribution systems.
- Provide low-cost energy to member cooperatives.
- Increase off-peak kWh sales.

Approximately 6,500 load control devices were installed by June 2011 along with another, 7,534 load control devices projected to be installed by December 2011. Each water heater has a peak reduction capability of 0.5 kW in the summer and 1.2 kW in the winter. Overall, Demand Response is projected to be 4 percent of Total Internal Demand.

Various utilities in the SERC-SE reporting area have residential energy-efficiency programs that may include:[223,224]

- Educational presentations
- Home energy audits
- Home inspector programs
- Compact fluorescent light (CFLs)
- Electric water heater incentives
- Heat pump incentives
- Energy-efficient new-home programs
- Energy Star-rated appliance promotions
- Appliance recycling programs
- Loans or financing options/incentives
- Weatherization
- Programmable thermostats
- Ceiling insulation

Commercial programs include energy audits, lighting programs, and plan review services.

Other programs such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits, and comfort advantage energy-efficient home programs promote reduced energy use, supply information, and develop energy-efficiency presentations for various customers and organizations. Also, many utilities within the SERC-SE reporting area are beginning to

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[222] http://www.powersouth.com/powerlines/september_2011.

[223] http://www.southerncompany.com/corporateresponsibility/electricity/championing.aspx.

[224] http://www.powersouth.com/powerlines/powerlines_newsletter_august_2011 .

work with their states' energy divisions on energy-efficiency planning efforts. Training seminars addressing energy efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

To address Measurement and Verification of energy-efficiency and DSM programs, SERC-SE reporting area entities may use third parties to conduct impact/process evaluations for commercial programs, or they may use load response statistical models to identify the difference between the actual consumption and the projected consumption absent the curtailment event. Response may also be tracked and verified by the readings of meters, as well as testing residential and commercial winter load-control programs for verification of demand reduction through generation dispatch personnel. Some entities conduct annual evaluations with a comprehensive report due at the end of a program cycle. Reports are projected to determine annual energy savings and portfolio cost-effectiveness. All on-peak Demand-Side Management data are shown below (Table 74).

Table 74: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**107**
Non-Controllable Demand-Side Management	
Direct Control Load Management	378
Contractually Interruptible (Curtailable)	1,234
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	92
Total Dispatchanle, Controllable Demand Response	**1,704**
Total Demand-Side Management	**1,811**

Some utilities within SERC-SE develop forecasts using econometric assessments based on approximately 29 to 40 years of weather (normal, extreme, and mild), economics, and demographics to assess demand variability.[225] The assumptions for the upcoming winter period show continued population growth to the region, even though the growth has slowed due to recent economic downturns.[226] Overall, decreases in expectations resulted in lower entity forecasts for winter energies and winter peak demand.

Generation

Utilities within the SERC-SE reporting area expect to have the aggregate on-peak capacity listed below to help meet demand during this assessment period. The Existing- (Certain, Other, and Inoperable) and Future (Planned and Other) resources in the SERC-SE Assessment Area are shown below (Table 75). Variable resources (i.e. wind and solar) are limited within this reporting area and are evaluated by analyzing their historical or projected output profiles. The result is a determination of the comparative capacity value to that of a typical combustion turbine on the system. Within SERC-SE, biomass (i.e. wood, wood waste, municipal solid waste, landfill gas, and ethanol) is the most viable renewable

[225] Historical peaks, Reserve Margins, and demand models are also used to predict variances (optimistic and pessimistic scenarios). Mild and extreme weather scenarios are captured within some entity models, whereas, other entities build reserves into the system to account for factors such as weather volatility and load forecast error.

[226] The forecast also shows steady positive economic trends and customer growth in the long run, but at slightly slower rates than last year's projections.

resource, as determined by some entities, as a result of low wind penetration in the area. *Future-Planned* biomass generation, other than landfill gas, is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events.

Table 75: SERC-SE Winter Capacity Breakdown

Capacity Type	2011/2012 Winter (MW)
Existing-Certain	64,857
Nuclear	5,795
Hydro/Pumped Storage	4,933
Coal	25,118
Oil/Gas/Dual Fuel	28,874
Other/Unknown	137
Solar	6
Biomass	17
Wind	-
Existing-Other	2,388
Existing-Inoperable	-
Future-Planned	-

Although the SERC-SE reporting area experienced moderate to extreme drought conditions throughout most of Alabama and Georgia, entities are predicting the upcoming winter hydro- generation output will be normal. Long-range precipitation forecasts released in July 2011 indicate an increased probability of below-normal rainfall for the season. If lower than normal rainfall occurs, it is anticipated that reservoirs can be managed to meet the short-duration peak demand that is typical of winter hydro-peaking operations. Daily system load demands will be met by combining hydro-generation with other generating resources. In addition, the potential lack of water available for cooling plants is not considered a concern in this reporting area for the upcoming season.

Overall, the area is not experiencing, and does not anticipate, any conditions (fuel limitations, weather, etc.) that would significantly reduce capacity for the winter or cause reliability concerns. SERC-SE reporting area entities also do not anticipate any existing significant generating units being out of service or retired during the winter season. Utilities are also preparing for the upcoming regulations that will impact future retirements and will continue work to manage regular scheduled generation maintenance. Adequate Reserve Margins will be maintained during these maintenance periods.

Capacity Transactions

The following SERC-SE imports and exports are reported for the upcoming 2011/2012 winter season (Table 76).

Table 76: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	3,061
	Expected	-
	Non-Firm	-
	Total	**3,061**
Exports	Firm	1,956
	Expected	-
	Non-Firm	-
	Total	**1,956**
Net Transactions		**1,105**

The majority of the imports and exports are reported to be backed by firm contracts for both generation and transmission. Of these contracts, 885 MW do not have firm transmission service and none are reported to be associated with LDCs or "make whole" Contracts. Only firm imports and exports have been included in the Reserve Margin calculations for the reporting area. Entities within the SERC-SE reporting area maintain emergency RSAs with organizations such as the SPP Reserve Sharing Group and entities internal to the area (approximately 200 MW). Other contract agreements with neighboring utilities provide capacity for outages of specific generation. Routine assessments are performed to account for forced outage rates, weather anomalies, and load forecast error. Overall, SERC-SE reporting area entities do not consider themselves dependent on outside imports or transfers to meet the demands of its load.

Transmission

New Bulk Electric System transmission facilities (transmission lines, transformers, and significant substation equipment) that are projected to be in-service for the 2011/2012 winter season are shown below (Table 77 and Table 78). Other than the project improvements listed below, entities have not added new technologies, systems, and/or tools to the system since last winter.

Table 77: SERC-SE New Transmission Facilities

Project Name	Status	Projected In-Service Date	Voltage (kV)
Plant Eaton-Hattiesburg Co. Drive	Complete	3/1/2011	115
Plant Eaton-Hattiesburg Co. Drive	Complete	3/1/2011	115
Hammock Bay Jct-Hammock Bay 1	Complete	3/30/2011	115
Flat Shoals-Union City	Complete	5/1/2011	230
Kiln-Carriere SW 1	Complete	5/1/2011	230
Deptford-Whitemarsh	Complete	5/1/2011	115
Morrow-Murray Lake Tap	Complete	5/1/2011	115
North Marietta-Roswell	Complete	5/1/2011	115
North Marietta-Smyrna	Complete	5/1/2011	115
Wright-Freedom Way 1	Complete	5/1/2011	115
North Theodore-Kroner (Dawes Tap)	Complete	5/10/2011	115
Holt-Tuscaloosa 1	Complete	5/25/2011	230
Plant McDonough CC-Plant McDonough (black) 2	Complete	6/1/2011	230
Plant McDonough CC-Plant McDonough (white) 1	Complete	6/1/2011	230
Silver Creek-Prentiss 1	Complete	6/1/2011	161
Meridian NE-Meridian PPL	Complete	6/1/2011	115
Meridian PPL-Meridian Primary	Complete	6/1/2011	115
Miflin-Wolf Bay	Complete	6/1/2011	115
Old Montgomery Jct-Old Montgomery	Complete	6/1/2011	115
Oswichee Jct-Oswichee	Complete	6/1/2011	115
Glendale-Defuniak Springs	Complete	6/3/2011	138
Liberty-Glendale	Complete	6/3/2011	138
Kingston Jct-Kingston 1	Complete	8/26/2011	115
Pt Washington Jct-Pt Washington 1	Complete	8/31/2011	115
Dale County-Bay Springs Jct.	Under Construction	11/4/2011	115

Table 78: SERC-SE Transformer Additions

Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	Projected In-Service Date	Description	Status
Waynesboro	230	161	4/1/2011	Waynesboro substation trasformer replacement.	Complete
Carriere SW	230	115	5/1/2011	New Substation	Complete
Factory Shoals	230	115	5/1/2011	New 230/115-kV substation with a 300MVA bank	Complete
Meldrim	230	115	5/1/2011	new 300 MVA, 230/115-kV transformer	Complete
Holt TS - Tuscaloosa TS Autobank	230	115	5/25/2011	Install 230/115kV Autobank at Tuscaloosa TS	Complete
Silver Creek Interconnection	161	115	6/1/2011	Silver Creek Interconnection	Complete

Currently, there are no major concerns with meeting in-service dates for transmission improvements. Additionally, entities are not expecting long-term outages during the winter period. Isolated maintenance outages may occur, but they are scheduled only during periods in which reliability is not threatened. If a scheduled outage cannot be supported without compromising the reliability of the system or the safety of personnel, the work necessitating the outage will be delayed or modified. Significant transmission constraints are not expected during the period. If constraints are identified in current operational planning studies, mitigation procedures are available to relieve constraints (generation adjustments, system reconfiguration or system purchases). Interregional transmission transfer capabilities for the upcoming winter are being finalized, publication is scheduled for late November 2011, and preliminary results indicate that there are no significant issues that will impact Bulk Electric System reliability.

Operational Issues

Operational studies are performed to assess conditions for 12 to 13 months into the future. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and firm transmission commitments for the time period studied and are often updated on a monthly basis. Additionally, reliability studies are conducted on two-day-out and next-day conditions. Studies are routinely updated as changing system conditions warrant and also take into account extreme winter weather scenarios. The current operational planning studies do not identify any unique operational problems or significant N-1 contingencies for the winter season.

Currently, there are no significant amounts of distributed resources installed within the SERC-SE reporting area; therefore, there are no anticipated operational changes, concerns, or special operating procedures related to distributed resource integration or minimum demand and over generation. Demand Response programs within the area are typically used during summer peaks and are not expected to be needed for reliability reasons this winter. Therefore, the current programs in place do not negatively impact reliability. Due to the economic downturn, the system carries more reserves than those needed to meet peak period planning targets.

Entities are currently studying the potential impact of environmental regulations, such as the current Cross-State Air Pollution Rule (CSAPR) and future regulations (specifically the MACT rules[227]) on the Bulk Electric System. Overall, no existing conditions are projected to impact the reliability on the Bulk Electric System because of environmental restrictions during the assessment time period.

The Southern control area routinely experiences significant loop flows due to transactions external to the control area itself. The availability of large amounts of excess generation within the Southeast U.S. results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs, or market conditions outside the Southern control area rather than by the actual load conditions within the control area. Significant changes in natural gas pricing dramatically impacts dispatch patterns. All transmission constraints identified in current operational planning studies for the winter assessment period can be mitigated through generation adjustments, system reconfiguration, or system purchases. Overall, there are no unusual operating conditions anticipated that could impact reliability for the winter.

Reliability Assessment

As stated above, entities within the SERC-SE reporting area use several methods to assess reliability. Powerflow studies in the operating and planning horizon monitor transmission facility loadings and steady state voltages for a variety of operating assumptions. Dynamic load modeling ensures acceptable transient voltage recovery thresholds are maintained. Plant stability studies ensure generating units stay

227 http://www.epa.gov/airtoxics/utility/utilitypg.html.

in synch, particularly for delayed clearing events. Resource adequacy studies help to monitor and manage future resource needs. These studies are done by individual companies or SERC study groups on a seasonal, daily, weekly or quarterly basis to ensure that resources are secured to meet demand.

The projected existing, anticipated and prospective winter-peak Reserve Margins for utilities in the SERC-SE reporting area are 55, 55, and 60.6 percent, respectively. The projected Reserve Margin for SERC-SE for the 2011/2012 winter season is 55 percent compared to last winter's projection of 52.7 percent. Utilities do not adhere to any regional/reporting area targets or Reserve Margin criteria. However, most investor-owned utilities maintain at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) Reserve Margin levels. Most SERC-SE reporting area entities use a target of 15 percent to ensure reliability and indicate that projected Reserve Margins remain well above this target. Recent analyses of load forecasts indicate that expected Reserve Margins remain well above 15 percent for the assessment period.

Analyses account for planned generation additions, retirements, deratings due to environmental control additions, load deviations, weather uncertainties, and forced outages and other factors. Current resource adequacy studies also account for load forecast error (LFE), weather effects on load, and unit outages.[228] Industry experience, system operations input, perceptions of acceptable risks, and an understanding of the strengths and weaknesses of the mathematical models were all considered in determining the optimum Reserve Margin.

The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak gas demand. Various companies within SERC-SE have firm transportation diversity, diverse fuel mixes, gas/coal storage, firm pipeline capacity, and on-site fuel supplies to meet the peak demand. When situations limit normal supply, established communications allow for additional supplies. These lines of communication include daily e-mails, phone calls, Internet accessibility, SCADA and instant messaging so that SERC-SE reporting area entities are well aware of fuels moving to various generating stations or to storage. Some utilities have implemented fuel storage, coal conservation programs, and various fuel policies to address concerns. These tactics help to ensure balance and create flexibility to serve anticipated generation needs. Relationships with coal mines and coal suppliers, daily communication with railroads for transportation updates, and ongoing communication with the coal plants and energy suppliers ensures that supplies are adequate and potential problems are communicated well in advance to enable adequate response time.

Utilities within the SERC-SE reporting area perform individual studies and maintain individual criteria to address any dynamic and static reactive issues. Studies are created each year for both the upcoming winter and usually for a future year case. The studies did not indicate any issues that would impact reliability in the 2011/2012 winter season. For example, several companies have performed fault-induced delayed voltage recovery (FIDVR) studies. To address dynamic reactive criterion, some utilities follow the practice of having a sufficient amount of generation on-line to ensure that no bus voltage is

[228] Some study methodologies apply Monte Carlo techniques to unit outages and minor factors while testing the entire sample set combinations of LFE and weather.

expected to be subjected to a delayed voltage recovery following the transmission system being subjected to a worst-case, normally cleared fault.[229] Prior to each winter, an operating study is performed to quantify the impact of generating units in preventing voltage collapse following a worst-case, normally cleared fault. The generators are assigned points, and the system must be operated with a certain number of points on-line depending on current system conditions, including the amount of load on-line and the current transmission system configuration. The study is performed over a range of loads from 105 percent of peak winter load down to around 82 percent of peak winter load conditions.

Other Area-Specific Issues

Entities within the SERC-SE reporting area are committed to maintaining the reliability of the system. Companies will continue to improve study methods and perform studies based on the most up-to-date information regarding load forecasts, transmission and generation status, and firm transmission commitments. Additional studies will be run as needed to assess specific situations. Any identified transmission constraints could be mitigated through generation adjustments, system reconfiguration or system purchases. Emergency Response Plans will also continue to be reviewed for improvement, while employees are trained and drilled on those procedures. Other entities are attending quarterly meetings with the Reliability Coordinator and neighboring utilities to discuss near term system projects and concerns throughout the region (ex: SEAMS Group[230]).

Assessment Area Description

SERC-SE is a summer-peaking reporting area covering portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida) with a population of approximately 35.1million[231]. Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 119,800 square miles. There are four Balancing Authorities within SERC-SE: PowerSouth Energy Cooperative, South Mississippi Electric Power Association, Southeastern Power Administration, and Southern Company Services, Inc.

[229] Studies of FIDVR involve modeling half of the area's load as small motor load in the dynamics model.

[230] http://www.spp.org/section.asp?group=544&pageID=27.

[231] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population.

SERC–W

Executive Summary

SERC-W (including SPP RC entities registered in SERC) is a summer-peaking reporting area covering portions of four southeastern states (Arkansas, Louisiana, Mississippi, and Texas). The 10 registered Balancing Authorities in this area are: Entergy, City of Benton, City of Conway, City of North Little Rock, AR, City of Osceola, City of Ruston, LA, City of West Memphis, Louisiana Generating, LLC, Plum Point Energy Associates, LLC, and Union Power Partners, L.P.

The projected 2011/2012 winter Total Internal Demand for utilities in the SERC-W reporting area (including Southwest Power Pool RC entities registered in SERC) is 19,931 MW, which is 856 MW (4.6 percent) higher than the projected 2010/2011 Total Internal Demand of 19,075 MW and 1,962 MW (9 percent) lower than the January 2011 winter peak of 21,893 MW. Entities in the area experienced lower than normal system-wide temperatures in the 2010/2011 winter during an extreme cold snap. Forecast assumptions are relatively unchanged and still reflect 10-year typical weather, retail and wholesale load growth. The capacity values expected to be available on-peak this winter are: *Existing-Certain* (36,682 MW), *Existing-Other* (3,269 MW), and Existing-Inoperable (1,200 MW). Since 2010, the amount of Existing Certain capacity has not increased. There are 108 MW of resources projected to be retired through the end of the assessment period and entities are not anticipating significant capacity additions this winter.

Aggregate 2011/2012 winter Reserve Margins are projected to be 91.8 percent, indicating capacity resources in the area are adequate to supply the projected firm demand. Existing- Certain and Net Firm Transaction, Anticipated and Deliverable winter peak Reserve Margins for utilities in the area are 92.3, and 91.8 percent, respectively. Although there are no regional/reporting area targets or Reserve Margin criteria for most entities in SERC-W, many plan to meet the requirements of reserve allocation as a member of the SPP Reserve Sharing Group, or to cover their most severe contingency on the system. These margins are above the 15 percent NERC Reference Marginal Level. Current entity processes in assessing demand, capacity and Reserve Margin projections are considered to be consistent with the assumptions portrayed in last winter’s reporting period.

Approximately 18 miles of new transmission have been added to the system in this area since the prior winter, as well as the addition of four autotransformers. In addition, one transformer project is expected to be put into service by the end of the assessment period. Currently, there are no significant transmission facility concerns that should impact Bulk Power System reliability for the season.

Entities are addressing concerns resulting from reliability studies by updating Curtailment Processes and Emergency Response Plans, transmission-wide and local area procedures, redispatch plans, and operating guidelines as necessary to minimize reliability challenges for the period. The SPP Independent Coordinator of Transmission-Entergy (SPP-ICTE), which is the area’s Reliability Coordinator, will continue to monitor the Acadiana area of Louisiana closely and implement mitigation plans as necessary; and utilities within the Acadiana area, such as Entergy, Cleco, and Lafayette Utilities have implemented a two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket. Phase 1 of the project was completed in May 2011, with the exception of the addition of a non-SERC-W utility's 230-138 kV autotransformer. The autotransformer is expected to be placed in service prior to the 2011/2012 winter season pending acceptable manufacture testing of the equipment. Phase 2 of the project is currently under construction and is on schedule to be completed by summer 2012. Companies in the area will continue to run area studies and regularly participate in various groups, such as the SERC NTSG and the ERAG MRSWS interregional studies. Overall, there are no other anticipated reliability concerns for the winter.

Demand

The projected 2011/2012 winter Total Internal Demand for utilities in the SERC-W reporting area (including SPP-RC entities registered in SERC) is 19,931 MW. This forecast is 856 MW (4.6 percent) higher than the winter 2010/2011 Total Internal Demand of 19,075 MW and 1,962 MW (9 percent) lower than the actual 2010 winter peak demand of 21,893 MW (Table 79). Entities report that they experienced lower than normal system-wide winter temperatures during an extreme cold snap. The internal peak demands of individual entities are aggregated as non-coincident peak values, and resource evaluations are normally based on summer peaking conditions. The forecast is based on a study that produced new econometrically-based forecasts of residential/commercial/industrial load, future economic/demographic conditions, and historical data. Forecast assumptions for the upcoming season are relatively unchanged and still reflect 10-year typical weather, retail and wholesale load growth.

Table 79: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**19,931**	**December-2011**
2010/2011 Forecast	19,075	January-2011
2010/2011 Actual	21,893	January-2011
All-Time Peak	22,042	January-2010

Demand Side Management (DSM) programs among the utilities in the SERC-W reporting area include: traditional industrial and large commercial interruptible rate programs, direct-control load management programs for agricultural customers, and a range of conservation/load management programs for all customer segments. The terms and conditions of these tariffs permit load curtailment at anytime, including winter months. There are no significant changes in the amount and availability of load management and interruptible demand since the last winter season. Demand Response is projected to be 3.6 percent of Total Internal Demand (Table 80).

Table 80: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**-**
Non-Controllable Demand-Side Management	
Direct Control Load Management	-
Contractually Interruptible (Curtailable)	723
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**723**
Total Demand-Side Management	**723**

Measurement and Verification (M&V) for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule and state regulators of Texas and Arkansas. As the programs advance, they will be incorporated in the retail sales and load forecast.

Energy-efficiency programs[232] are implemented to distribution cooperatives and the residential sector. A variety of programs have been added to company portfolios over the years, ranging from:

- Home energy audits
- CFLs
- Energy Star-rated washing machines and dishwashers
- Energy Star-rated heat pumps and air conditioners
- Weatherization and high efficiency water heaters.

Annual M&V programs measure energy savings and costs for each of these energy-efficiency programs. Information from these M&V programs will be used to fine tune energy-efficiency programs and to determine their cost-effectiveness. The current forecast includes energy-efficiency programs that have received regulatory approval.

Load scenarios for outage planning purposes are developed regularly to address variability issues in demand. These load scenarios set each weekly peak and are based on historical temperature probabilities. Scenarios are also regularly developed and posted to the OASIS for transmission-planning load flow analyses. Peak load scenarios are also based on assumptions of extreme weather (i.e.: more severe than the expected peaking conditions, but less severe than the most severe conditions found in the historical records). Assumptions such as normal weather, economic, and demographic conditions are included, but are relatively unchanged and still reflect retail and wholesale load growth. Finally, load forecast sensitivity analysis is regularly developed to support long-term planning across a variety of scenarios.

[232] http://www.entergy.com/our_community/environment/energy_efficiency.aspx

Generation

Companies within the SERC-W reporting area expect to have the following Existing (Certain, Other, and Inoperable) and Future (Planned and Other) capacity on-peak (Table 81).

Table 81: SERC-W Winter Capacity Breakdown

Capacity Type	2011/2012 Winter (MW)
Existing-Certain	36,682
Nuclear	5,295
Hydro/Pumped Storage	259
Coal	6,300
Oil/Gas/Dual Fuel	24,828
Other/Unknown	-
Solar	-
Biomass	-
Wind	-
Existing-Other	3,269
Existing-Inoperable	1,200
Future-Planned	(108)

Entities report that only firm capacity is counted toward the peak in calculations. In most cases, variable resources are not counted due to their irregularity during peak demand periods. However, other entities may consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest 10 percent of load hours for the respective month and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value.

Hydro conditions are projected to be normal for the winter assessment period and are based on current reservoir levels and rainfall. No significant reliability impacts or abnormal conditions are expected for the upcoming season.

Reporting area entities are also not expecting any conditions associated with weather, fuel supply, or fuel transportation that would reduce capacity. Portfolios of firm-fuel resources ensure adequate fuel supplies to generating facilities during projected winter peak demand. Those resources include nuclear and coal-fired generation that are relatively unaffected by winter weather events, fuel oil inventory located at the dual-fuel generating plants, approximately 10 Bcf (Billion Cubic Feet) of natural gas in storage at natural-gas storage facility owned by a SERC-W reporting area company, short-term purchases of firm natural gas generally supplied from other gas storage facilities, and delivered using firm-gas transportation contracts. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of weather and fuel transportation conditions that might otherwise reduce generating capacity.

Routine maintenance outages are scheduled for some generating units during the winter. Outage plans are developed so that loads can be met with available resources. Outside of these routine outages, there are no other anticipated system conditions expected for the winter. Entities have engaged both internal resources and outside experts to assist with the development of compliance scenarios that will include estimating increased capital and annual operating costs from implementing various potential pollution control measures[233]. These efforts are ongoing, and results are currently not available. Various studies are in progress assessing the potential impacts to meet the EPA's Cross State Air Pollution Rule ("CSAPR") requirements through redispatch. New demand-side resources such as energy-efficiency and load management programs could be used as a resource to help meet CSAPR requirements, however, new programs would take time to design, obtain regulatory approval, implement and gain reasonable scale.

Capacity Transactions

The following imports and exports are anticipated for the 2011/2012 winter (Table 82). These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area.

Table 82: On-Peak Capacity Transactions

	Transaction Type	Winter 2011/2012 (MW)
Imports	Firm	2,963
	Expected	-
	Non-Firm	-
	Total	**2,963**
Exports	Firm	2,701
	Expected	-
	Non-Firm	-
	Total	**2,701**
	Net Transactions	**262**

All contracts for these imports/exports are backed by firm transmission and are tied to specific generators. No imports/exports have been reported to be based on partial path reservations. However, approximately 209 MW are "make whole" contracts.

The reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the demands of its load. Most entities within the SERC-W reporting area are members of the SPP Reserve Sharing Group. These reserves are not counted or relied on in the resource adequacy assessment, or for capacity or Reserve Margins. System operators generally coordinate the scheduling and transmitting of the reserves to meet the specific reliability needs of the system.

Transmission

The following table shows new Bulk Electric System transmission facilities (transmission lines, transformers, and significant substation equipment) since the 2010/2011 winter that are anticipated to be in-service for the upcoming winter. No delays are expected for the reported projects (Table 83and Table 84).

[233] http://www.epa.gov/airtransport/

Table 83: SERC-W Expected Transmission

Project Name	Status	Projected In-Service Date	Voltage (kV)
Jacinto-Lewis Creek 1	Complete	3/2/2011	230
Sellers Road-Meaux 1	Complete	5/6/2011	230
North Crossett-North Bastrop 1	Complete	6/15/2011	115
Sterlington-North Bastrop 1	Complete	6/15/2011	115
Osage Creek-Grandview 1	Under Construction	12/15/2011	161

Table 84: SERC-W Transformer Additions

Project Name	Voltage		Projected In-Service Date	Description	Status
	High-Side (kV)	Low-Side (kV)			
Add auto at Lewis Creek	230	138	3/2/2011	Add a 230/138 auto at Lewis Creek	Complete
Acadiana Area Improvement Project Phase 1	230	138	5/6/2011	Add 230-138 kV auto at Meaux	Complete
Acadiana Area Improvement Project Phase 1	500	230	5/6/2011	Add 500 kV terminal at Richard for new Cleco 500-230 kV auto	Complete
McAdams Area Upgrades	500	230	6/2/2011	Add second auto at McAdams at 560 MVA	Complete
Sarepta Project	345	115	6/15/2011	Construct a new 345-115 kV substation consisting of a 500 MVA auto. Cut station into EL Dorado to Longwood 345 kV line	Complete
Holland Bottoms 500-115	500	115	12/1/2011	Add a new 500-115 kV Substation in Little Rock	Under Construction
Bayou LaBoutte Substation	500	230	12/15/2011	Construct new 500 kV substation and install 800 MVA 500-230 kV autotransformer	Under Construction

There are no significant planned transmission facility outages that impact Bulk Electric System reliability for this winter season. Prior to the approval of any proposed maintenance outages, studies are completed to identify potential impacts on reliability.

No transmission constraints are projected to significantly impact Bulk Electric System reliability for the 2011/2012 winter. Companies within the SERC-W reporting area regularly participate in SERC NTSG seasonal reliability studies and in the ERAG MRSWS interregional studies. These studies include a review of subregional-to-subregional and company-to-company transfer capabilities, taking into consideration generation and transmission topology outside of the area.

The preliminary NTSG 2011/2012 Winter Reliability Study results indicate that transfer limits for imports are at or above transfer test levels for the 2011/2012 winter peak season. The import levels indicated by the results of this 2011/2012 winter study are limited by various constraints and not just one facility, as in the past with the McAdams 500/230 kV autotransformer. Furthermore, since all the planned upgrades associated with the McAdams 500/230 autotransformer and planned additions have been completed since June 2011, import capability levels are expected to increase from all transfer directions.

Entities will continue to evaluate the transmission system to identify any future constraints, and will work to mitigate concerns that could significantly impact reliability in the future.

Operational Issues

The companies within the reporting area that are transmission-dependent rely on operating studies that are performed by transmission operators. Resource availability, fuel availability and hydro conditions are expected to be normal during the winter. Loss-of-Load studies are performed annually for the regulated utility for the current year based on updated load forecast and unit availability data. The long-term test of resource adequacy is met by achieving a 16.9 percent planning Reserve Margin. No additional studies are expected to be performed for the upcoming winter months.

Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for transmission loading relief (TLR) and managing minimum generation problems. An energy forecasting package is used to predict wind farm output given meteorological data collected at the wind farms. In addition, SERC-W reporting area entities are not anticipating reliability concerns resulting from minimum demand and over generation, and high levels of Demand Response resources.

As mentioned above, entities are continuing evaluations on the impacts of CSAPR. Most preparations include newly developed compliance plans that will provide the best opportunity for meeting the extremely short CSAPR deadlines. Other companies are hiring consultants to assess the cost of improvements or alternative generation availability. Variables such as equipment performance levels and the availability and pricing of allowances could result in capacity reductions from generating stations. Overall, entities confirm that there do not appear to be reliability impacts to the system from environmental concerns or unusual operating conditions for the upcoming season. Reliability is expected to be maintained at the required operating margins.

Reliability Assessment

Many assessments are performed throughout the SERC-W reporting area to assess reliability. Powerflow studies in the operating and planning horizons monitor transmission facility loadings and steady state voltages for a variety of operating assumptions. Dynamic load modeling ensures acceptable transient voltage recovery thresholds are maintained. Plant stability studies ensure generating units stay in synch, particularly for delayed clearing events. Resource adequacy studies help to monitor and manage future resource needs. These studies are done on a seasonal, daily or quarterly basis to ensure that resources are secured to meet demand.

The existing, deliverable and prospective winter-peak Reserve Margins for utilities in the reporting area are projected to be 92.3, 91.8, and 102.4 percent, respectively. This winter’s aggregate margins of 91.8 percent are higher than last year’s margins of 74.9 percent. There are no regional/reporting area targets or Reserve Margin criteria for any of the SERC reporting areas, but many entities in SERC-W plan to meet the requirements of reserve allocation as a member in the SPP Reserve Sharing Group or plan to cover the most severe contingency on their system. These entities have reported no significant changes to the Reserve Margin from 2010 reporting to the current winter.

Various utility resource planning departments in the area conduct studies annually (either in-house or through contractors) to assess resource adequacy. Modeling of resources and delivery aspects of the power system are used in all phases of the studies. One example of an entity's method would be Entergy's use of their Entergy Reliability Analysis with Interruptible Loads (ERAILS) model. This model is a proprietary computer simulation model developed by the Entergy Generation Planning group to perform the resource requirements analyses.[234] The fundamental objective of the process is to identify the amount of incremental resources necessary to serve firm load at a reliability level of no more than 1 day/10 years LOLE and to serve interruptible retail and limited-firm wholesale loads with an average of 10 or fewer days of interruption during the year.

Resource adequacy studies performed within the SERC-W reporting area take into account potential resource deactivations and anticipated unit outages, existing and owned resources, and limited and long-term purchase contracts. Results help develop 1-year and 10-year resource plans that meet target Reserve Margins.

Fuel supplies are anticipated to be adequate. Coal stockpiles are maintained at 45 days or more. Natural gas contracts are firm, with some plants having fuel oil back-up. Extreme weather conditions should not affect deliverability of natural gas for the upcoming winter season. Upon the occurrence of fuel interruption or forced outage within some entity facilities, it is common that exporting contracts out of the facility will be curtailed in coordination with the affected Balancing Authorities until operations can return to normal. Typically, natural gas supplies are limited only when there are hurricanes in the Gulf of Mexico, which is not a concern during the winter. There is access to local gas storage to offset typical gas curtailments. Many utilities with the SERC-W reporting area maintain portfolios of firm-fuel resources, which include nuclear and coal-fired generation that are relatively unaffected by weather events, to ensure adequate fuel supplies to generating facilities during projected peak demand. Various portfolios contain fuel oil inventories located at dual fuel generating plants, approximately 10 Bcf of natural gas in storage at a natural-gas storage facility owned by a company located within the SERC-W reporting area, short-term purchases of firm natural gas generally supplied from other gas storage facilities, and firm-gas transportation contracts. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of potentially problematic issues on system reliability. Close relationships (contracts) are maintained with coal mines, gas pipelines, gas producers, and railroads that serve coal power plants to ensure adequate fuel supplies are on hand to meet load requirements.

Individual studies are performed throughout the area to assess transient dynamics, voltage, and small-signal stability issues for winter conditions in the near-term planning horizons, as required by NERC Reliability Standards. These entities also participate in various SERC study groups to annually assess

[234] The ERAILS model uses Monte Carlo statistical techniques to estimate each day's "actual" peak load based on the forecast load and the load forecast variance, the total resources available to serve that load based on available resources, forced outages, the characteristics of each resource, and the probability of being able to meet the load, plus off-system sales and operating reserves.

potential issues on the system. Specifically for the 2011/2012 winter, a dynamic study was performed under the NERC Reliability Standards TPL-001-0 through TPL-004-0.[235] Various tools (smart screening tool, the Fast Fault Screening (FFS) Module of Physical and Operational Margins – Transient Stability) were used to rank the contingencies that were simulated in the study for single-line-to-ground or three-phase faults (with normal or delayed clearing).

Other Area-Specific Issues

SERC-W reporting area entities are studying reliability with a critical and conservative approach to minimize reliability concerns for the winter period. Any issues that result from the studies are addressed within the appropriate timeframe. Curtailment Processes and Emergency Response Plans are routinely updated to help mitigate operating emergencies that may affect reliability. Transmission-wide and local area procedures redispatch, and operating guidelines will be implemented to maintain reliability for the winter as necessary. Because Energy Emergency Alerts (EEA) have been issued in the past for the Acadiana area, the SPP-ICTE will continue to monitor this area closely and implement mitigation plans as necessary as part of its Reliability Coordinator function.

Utilities within the Acadiana area have implemented a two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket. Phase 1 of the project was completed in May 2011, with the exception of the addition of a non-SERC-W utility's 230-138 kV autotransformer to be located at one of their substations near the Moril area in the southern portion of the load pocket. The autotransformer is expected to be placed in service prior to the 2011/2012 winter season pending acceptable manufacture testing of the equipment. Phase 2 of the project is currently under construction and is on schedule to be completed by summer 2012. Overall, there are no other anticipated reliability concerns for the upcoming winter.

Assessment Area Description

SERC-W (including SPP RC entities registered in SERC) is a summer-peaking reporting area covering portions of four southeastern states (Arkansas, Louisiana, Mississippi, and Texas) with a population of approximately 34.1million.[236] Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 133,500 square miles. There are 10 registered Balancing Authorities within the SERC-W reporting area: Entergy, City of Benton, City of Conway, City of North Little Rock, AR, City of Osceola, City of Ruston, LA, City of West Memphis, Louisiana Generating, LLC, Plum Point Energy Associates, LLC, and Union Power Partners, L.P.

[235] http://www.nerc.com/page.php?cid=2|20

[236] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population

SPP

Executive Summary

SPP's Demand projection for the 2011/2012 winter includes the SPP RE registered entities along with the addition of the Nebraska members and Arkansas Electric Cooperative Corporation's (AECC) Entergy footprint (SPP RTO).[237] Total Internal resources are expected to be 69,332 MW, of which 63,632 MW are *Existing-Certain* resources. 10,292 MW of *Existing-Certain* resources have been added since the 2010/2011 Winter Assessment.[238] Future Planned resources that are expected to be in service during the assessment timeframe total 45.5 MW of hydro and wind. There are no significant capacity additions or retirements scheduled during the assessment timeframe. However, the Environmental Protection Agency's (EPA) recently adopted Cross State Air Pollution Rule (CSAPR) could have bearing on the SPP footprint as early as January 2012.

SPP RTO's capacity margin requirement is 12 percent, which translates to a Reserve Margin of 13.6 percent, for the Region.[239] The Reserve Margin for the SPP RTO Region, based on the *Existing-Certain* and Net Firm Transactions is 62.6 percent, and the Reserve Margin based on the Deliverable Capacity Resources is 62.7 percent for the upcoming 2011/2012 winter. The projected Reserve Margins for the 2011/2012 winter are well above the SPP RTO's minimum required capacity margin.

There are still reliability concerns in the Acadiana Load Pocket (ALP) area, but these concerns have decreased due to the recent addition of a new 230 kV transmission line in the area. The ALP area, located in southern Louisiana, spans both the SPP RE and SERC reliability areas and continues to be constrained as transmission improvements are being constructed. The SPP RTO has been aware of congestion issues in this area since 2006 due to the lack of efficient generation and transmission capacity that limit the amount of import capability. The City of Lafayette, CLECO, and Entergy are in the process of constructing transmission additions and upgrades in the Region. The first phase of the project, which includes a 230 kV line from Roark to Sellers Rd., was energized on May 3, 2011. This line has already alleviated some of the most limiting elements in the ALP by as much as 10 percent. The second phase, Sellers Rd. to Segura, energized in October 2011, will further alleviate congestion. Completion of the entire project is expected in the winter of 2012 and should significantly improve transmission congestion for the ALP.

As a result of the winter weather that occurred February 1-5, 2011 across the middle portion of the United States, numerous generators experienced freezing components and outages, including those owned by several entities in the SPP RTO footprint. These entities have reviewed their winter weatherization processes and procedures and in some cases have made some modifications to their preparations and/or emergency operating plans such as establishing a Command System to prepare for and execute during weather events of this type.

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[237] Arkansas Electric Cooperative Corporation's Entergy footprint is included with SPP's assessment due to NERC's restructuring of reporting responsibilities.

[238] The 10,292 MW's includes the addition of reporting new resources plus Nebraska and AECC Entergy resources.

[239] SPP Criteria 2.1.9 http://www.spp.org/publications/Criteria02042010-with percent20AppendicesCurrent.pdf.

The Federal Energy Regulatory Commission (FERC) and the North American Reliability Corporation (NERC) made a number of recommendations[240] for the electric industry following their investigation of the event, and SPP RE is supportive of these recommendations. The SPP RE believes that many of the recommendations may already be incorporated into the registered entities' winter preparations, but there may also be opportunities for improvement and/or the sharing of lessons learned. Therefore, SPP RE is conducting a survey of the registered entities in the SPP RE footprint and expects to have results in December 2011. Additional information on winter weatherization can be found in the *Generation* section.

There were approximately 307 miles of 100-345 kV transmission line additions since the previous reporting year. Approximately 24 miles of 100-345 kV transmission line additions are expected to be in service through the assessment timeframe. Other than the ALP area, there are no known transmission reliability concerns identified during the assessment timeframe.

In 2011 SPP implemented a new wind forecasting tool to generate five-minute, hourly, and day-ahead predictions. To make the most efficient and effective use of renewable resources, SPP's operations staff predicts how much wind generation will be available to reliably serve load over given time periods. The most significant obstacle to effectively integrating wind energy into SPP's generating mix has been its unpredictability. As wind speed changes, a utility relying on that output must instantaneously vary the output of other generating resources to compensate for the wind variability. Being able to more accurately predict when, where, and how hard the wind will blow will have a significant and positive impact on grid operations.

Introduction

Southwest Power Pool, Inc. (SPP) operates and oversees the electric grid in the southwestern quadrant of the Eastern Interconnection. In addition to serving as a NERC Regional Entity (RE), SPP is a FERC-recognized Regional Transmission Organization (RTO). The SPP RTO footprint includes all or part of nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.[241] The Nebraska members belong to the Midwest Reliability Organization Regional Entity, but this year's assessment is being performed on the RTO footprint so the Nebraska members will be included in the SPP report and the region will be referred to as SPP RTO.

This report gives a high-level overview of the 2011/2012 winter reliability assessment for the SPP RTO Region; specifically demand growth, capacity adequacy, and operational reliability. The winter assessment is used to identify any areas of concern regarding reliability for the SPP RTO region.

This report is created with data and information submitted by SPP Reporting Entities, which is validated and cross-checked to verify consistency. Once this process has been completed, SPP RE staff aggregate

[240] FERC NERC Report on the February 2011 Southwest Cold Weather Event: http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

[241] To read more about the differences between the SPP RE and SPP RTO footprints, open the Footprints document on the SPP.org Fast Facts page: http://www.spp.org/publications/SPP_Footprints.pdf.

the information into one data set for the entire SPP RTO region. SPP RE staff use a peer review process to validate the data and develop the reliability assessments.

The winter assessment evaluates the forecasted demand, capacity resources, and future capacity additions for the upcoming winter timeframe. New bulk transmission (greater than 100 kV) that has been installed since the last winter assessment, through the end of the current winter assessment, is reported. Projected operational and reliability concerns are also addressed for the upcoming winter timeframe.

Demand

The projected non-coincident total internal demand forecast for the 2011/2012 winter peak is 41,089 MW, and the actual 2010/11 winter peak demand was 42,397 MW, both of which are based on the SPP RTO footprint (Table 85). Comparison to the previous forecast is unavailable due to the change in footprint reporting requirements between assessments. Forecast data is collected from individual reporting members as monthly non-coincident values and then summed to produce the total forecast for the SPP RTO. The summer peak is the peak condition upon which the SPP RTO Region bases its resource evaluations.

Table 85: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	**41,089**	**January-2012**
2010/2011 Forecast	31,377	February-2011
2010/2011 Actual	42,397	February-2011
All-Time Peak	40,968	January-2011

Each SPP RTO member provides their demand response programs and subtracts those values from their load forecasts to report the net load forecast. Based on the SPP RTO members' inputs, currently 819 MW of contractually interruptible demand and 93 MW of direct control load management are reported (Table 86). SPP does not have a demand response verification process in place due to the minimal amount of megawatts contained in the programs. The percentage of demand response programs that can reduce peak demand against the Total Internal Demand is 1 percent.

Table 86: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**151**
Non-Controllable Demand-Side Management	
Direct Control Load Management	93
Contractually Interruptible (Curtailable)	819
Critical Peak-Pricing (CPP) with Control	-
Load as a Capacity Resource	-
Total Dispatchanle, Controllable Demand Response	**912**
Total Demand-Side Management	**1,062**

SPP RTO members are reporting 151 MW of energy efficiency programs for the assessment timeframe. In March 2010, SPP RTO member Oklahoma Gas and Electric (OG&E) installed approximately 42,000 smart meters on customer homes in Norman, Oklahoma, along with the information delivery infrastructure to carry the information to and from the customers and OG&E. An estimated 3,000 Norman customers will be asked to participate in a study during the winter of 2011 using the in-home devices and/or Internet portals as a means to get electricity pricing and usage information.[242]

Although actual demand is very dependent upon weather conditions and typically includes the effects of interruptible loads; forecasted net internal demands are based on a 10 to 30 year average winter weather, or 50/50 weather.[243] Some SPP RTO members base their peak load forecast on a 50- percent confidence level as approved by their respective state commission(s). SPP RTO does not expect any immediate impact on Regional reliability due to current economic conditions; colder winter conditions have had more of an impact on the forecast swings.

In October 2010, the SPP RTO completed the Loss- of- Load Expectation (LOLE) and Expected Unserved Energy Study for the 2016 time period.[244] The study evaluated the need to adjust SPP's 12 percent capacity margin or 13.6 percent Reserve Margin, and estimated the Reserve Margin required to achieve an LOLE of no more than 1 day in 10 years. Based on the LOLE study performed by SPP RTO staff in 2010 for the summer of 2016, the capacity or Reserve Margin requirement for the SPP RTO remained unchanged. The 12 percent capacity margin and 13.6 percent Reserve Margin requirements are also cross-checked annually in the EIA-411 reporting, as well as through supply adequacy audits the SPP RTO conducts every five years of Regional members. The last supply adequacy quality check was conducted in 2007.

The SPP RTO bases its seasonal assessments on the near-term load forecast; if the load forecast shows an extreme winter condition then that condition will be studied.

Generation

SPP RTO expects to have 69,332 MW of total internal resources for the upcoming winter season. This consists of *Existing-Certain* Capacity of 63,632 MW, *Existing-Other* Capacity of 5,376 MW, *Existing-Inoperable* Capacity of 279 MW, and Future Capacity resources of 45.5 MW.

Of the 3,755 MW of variable generation (mostly wind) connected to the SPP RTO transmission system, the expected on peak capacity is 93 MW.[245] The expected on peak biomass portion (landfill gas) is 7 MW. The hydro capacity within the SPP RTO region represents a small fraction of the total resources

[242] OG&E's study to evaluate their smart meter program began with data collection in 2010.

[243] SPP RTO members use different historical yearly averages with the least amount being 10 years and the greatest being 30 years.

[244] SPP.org>Engineering>2010 Loss-of-Load Expectation (LOLE) Report : http://www.spp.org/publications/LOLE%20Report_5%20Draft_cc.pdf.

[245] Wind resources could not be counted toward on-peak capacity unless 4 years of historical operational data was available for reference. The SPP Criteria for wind resource reporting has changed and will have an impact on the on-peak wind numbers going forward, starting with the 2011 LTRA.

(approximately 2,098 MW). SPP RTO monitors potential fuel supply limitations for hydro and gas resources by consulting with its generation owning/controlling members at the beginning of each year.

Since hydro capacity is only a small fraction of SPP RTO resources reservoir levels do not materially impact the SPP RTO Reserve Margins. The SPP RTO region is not expected to experience drought conditions during the winter season that would impact reservoir levels, affect thermal generating units or prevent the region from meeting their capacity needs. There are no known conditions that would reduce capacity within the Region, however, federal environmental regulations, and in particular the CSAPR, may impact the region as discussed in the *Reliability Assessment* section. There are no significant generating units planned to be out of service or retired prior to the winter season.

Several entities in the SPP RTO footprint experienced generator outages during the Southwest Cold Weather Event that occurred February 1-5, 2011 and as a result reviewed their winter weatherization procedures for the coming winter. The entities in the SPP RTO footprint operate in winter weather conditions every year and as a result make preparations each year for such conditions. Winter preparation varies by entity and type of generating unit, but typically begins in the fall and includes inspection of freeze protection equipment and winterization of various generator components such as pump houses and cooling towers. When severe winter weather approaches, additional preparation takes place such as adding additional staff and critical inventory ahead of the event. Individual entity contact with fuel suppliers may be done to ensure adequate fuel supplies are on hand and/or available. One area in particular that the Southwest Cold Weather Event highlighted in the SPP region is the need to identify natural gas supply or processing facilities as critical loads to avoid taking them off-line during rolling blackouts as this may cause cascading events back to the electric system.[246]

Capacity Transactions

SPP RTO members have reported the following imports and exports for the 2011/2012 winter (Table 87). All firm power contracts are backed by transmission and generation and none of the sales contracts are Liquidated Damages Contracts.

Table 87: On-Peak Capacity Transactions

Transaction Type		Winter 2011/2012 (MW)
Imports	Firm	4,095
	Expected	25
	Non-Firm	-
	Total	**4,120**
Exports	Firm	2,382
	Expected	-
	Non-Firm	-
	Total	**2,382**
	Net Transactions	**1,738**

[246] The *FERC/NERC Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5* highlighted this same issue. See page 204.

SPP RTO members along with some members of the SERC region have formed a Reserve Sharing Group. The members of this group receive contingency reserve assistance from other SPP RTO Reserve Sharing Group members, but it does not require support from generation resources located outside the SPP RTO Region. The SPP's RTO Operating Reliability Working Group (ORWG) sets the Minimum Daily Contingency Reserve Requirement for the SPP RTO Reserve Sharing Group. The SPP RTO Reserve Sharing Group maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on-line.

Transmission

The bulk power system transmission projects the SPP RTO has defined as Under Construction or Planned to be in service during the assessment timeframe are shown below (Table 88 and Table 89).

Table 88: SPP Expected Transmission

Project Name	Status	Projected In-Service Date	Voltage (kV)
WFEC Snyder to AEP Snyder[247]	Under Construction	09/01/2011	138
Acadiana Load Pocket (ALP)	Under Construction	10/01/2011	230
Turk – Okay	Under Construction	11/01/2011	138
Piper to Wolcott Transmission Line	Under Construction	12/01/2011	161
East-Fairfax to Fairfax Transmission Line	Under Construction	12/01/2011	161
East-Fairfax to GM Transmission Line	Under Construction	12/01/2011	161
Quindaro to Nearman Transmission Line	Under Construction	12/01/2011	161
Siloam Springs Tap-Siloam Springs	Under Construction	12/01/2011	161
Johnson Draw	Under Construction	12/01/2011	115
Anadarko SW 138 kV	Under Construction	12/01/2011	138
Anadarko SW to Washita	Under Construction	12/01/2011	138

Table 89: SPP Transformer Additions

Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	Projected In-Service Date	Description/Status
Tonnece Substation	345	161	12/01/2011	Planned Installation - Transformer Enroute from factory
Hitchland Project	230	115	12/01/2011	Project in final design

There are no known concerns with meeting the target in-service dates or placing these projects in service during peak load periods for reliability projects that have been approved by the SPP RTO Board of Directors. Assuming these projects come on line as scheduled, there are no known transmission constraints that could impact the reliability of the SPP transmission grid. The SPP RTO relies heavily on

[247] The AEP Snyder 138 kV line (approximately 1 mile) is complete.

its Project Tracking process to monitor projects and ensure they meet their required in-service dates.[248] If a project's timeline is extended due to construction delays or other unforeseen issues, the SPP RTO will conduct a study to address any reliability issues associated with the extension.

Two transformers have been added since the previous winter timeframe, both of which were energized in October 2011. A 230 kV/138 kV autotransformer was added to the Segura substation and a 345/138 kV transformer was added to the Johnston County substation. There are no significant transmission lines or transformers scheduled to be out of service during the assessment timeframe.

The ALP area located in southern Louisiana spans both the SPP RE and SERC reliability areas and continues to be constrained as the transmission improvements for this area are being constructed. The congestion issues in the ALP area are due to a lack of efficient generation and transmission capacity inside the load pocket that limit the amount of import capability. The City of Lafayette, CLECO, and Entergy are in the process of finalizing the construction of several reliability additions and upgrades which will be completed in 2012. The first phase of the project, a 230 kV line from Roark to Sellers Rd., was energized on May 3, 2011. This line has already alleviated some of the most limiting elements in the ALP by as much as 10 percent. The other phase of the project, energized in October 2011, is a 230 kV line from Sellers Rd. to Segura. Final completion of the project in 2012 should further alleviate some of the transmission congestion in this area.

SPP staff participates in one of the Eastern Interconnection Reliability Assessment Group's[249] interregional study efforts. This study is conducted to examine the potential constraints on the SPP RTO region as a result of simulated imports and exports with neighboring regions. Preliminary study results indicate that SPP imports are limited due to the 161 kV facilities across the Arkansas-Oklahoma border. This has been a known issue for the last several years, and the SPP RTO is working with SERC members on mitigating this in the near future. In the meantime, the SPP RTO does not expect any reliability issues for winter 2011/12, as it does not rely on the incremental transfer capability from neighboring regions to meet the projected demand.

Operational Issues

For the upcoming winter, SPP RTO projects less than two (2) percent on-peak wind capacity of the total nameplate wind capacity connected to the SPP RTO transmission system. SPP RTO grid operators will continue to monitor any operating challenges for this assessment period.

SPP RTO does not foresee any unmanageable reliability concerns due to minimum demand and over generation. Reliability Coordinator directives may be used to force some generation offline in the case of over generation. In some local cases, generation that may need to be directed offline to accommodate wind variability must be back online for load pickup in a time period less than the minimum down time. Widespread balancing issues are not expected due to generation fleet flexibility.

[248] The Engineering and Planning section of SPP.org has a page on Project Tracking: http://www.spp.org/section.asp?pageID=114.
[249] https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/Pages/default.aspx

Local congestion in areas with excess generation may require cycling of units or re-evaluation of short term SOL values.

There are no concerns with the use of demand response resources to meet peak demands due to the small amount of Demand Response on the SPP RTO system.

Proposed federal environmental regulations and specifically the recently finalized CSAPR could cause operational impacts in the SPP RTO footprint as early as January 1, 2012.[250] While SPP RTO members have not had time to fully analyze the impacts of this rule on their individual systems, early indications from SPP RTO members are that operational changes such as fuel switching, re-dispatch to utilize lower emission units to the extent possible, and management of environmental restrictions in off-peak hours may be necessary. The discussion contained in the *Reliability Assessment* section contains a discussion on the potential reliability impacts from the CSAPR.

There are no known reliability concerns resulting from high levels of demand response resources as demand response resources in the SPP RTO Region are minimal at this time.

There are no anticipated unit outages or need for the use of temporary operating measures that are foreseen for this winter. There are no new Smart Grid programs that have been fully implemented within the past year that will have any influence on reliability of the Region. There are no known unusual operating conditions, that have not already been discussed, that could impact the reliability of the Region for the upcoming assessment timeframe.

Reliability Assessment

Currently, SPP RTO criterion requires that its members maintain a minimum capacity margin of 12 percent (13.6 percent Reserve Margin). SPP RTO members, by meeting this requirement, adequately cover a 90/10 weather scenario. The SPP Reserve Margin, based on Existing resources, is expected to be 62.6 percent for 2011/2012 winter. The 2010/2011 winter Reserve Margin was projected to be 75 percent, but was based on the SPP RE footprint,[251] and the 2011/2012 winter projected Reserve Margin is now based on the SPP RTO footprint. On a Deliverable resources basis, SPP has sustained around a 62.7 percent Reserve Margin. The Reserve Margin with Prospective capacity resources for the same period is 71 percent.

Based on the LOLE study performed by SPP RTO staff last year for the 2011 study period[252], the capacity or Reserve Margin requirement for SPP RTO remained unchanged. Additionally, the 12 percent capacity margin or 13.6 Reserve Margin requirements is also checked annually in the EIA-411 reporting as well as through supply adequacy audits of regional members conducted every five years by the SPP RTO. The last supply adequacy audit was conducted in 2007.

[250] The EPA finalized the rule on July 11, 2011. Emission reductions under the Cross-State Air Pollution Rule will begin to take effect quickly. The first phase of compliance begins January 1, 2012 for SO_2 and annual NOX reductions and May 1, 2012 for ozone season NOX reductions. The second phase of SO2 reductions begins January 1, 2014.

[251] Per NERC instruction SPP's assessments are based on the RTO footprint, not on the RE footprint as was done in years past.

[252] Loss-of-Load Expectation (LOLE) Report : http://www.spp.org/publications/LOLE%20Report_5%20Draft_cc.pdf.

Due to the diverse generation portfolio in the SPP RTO, there is no concern of the fuel supply being affected by winter weather extremes during peak conditions. If there is to be a fuel shortage, SPP RTO members are to communicate to SPP RTO operations staff in advance so that they can take the appropriate measures that SPP RTO would enact if capacity or reserves become insufficient due to unavailable generation. In that case, SPP RTO would declare either an EEA (Energy Emergency Alert) or OEC (Other Extreme Contingency) and post as needed on the RCIS (Reliability Coordinator Information System). SPP RTO does not expect any immediate impact on the reliability of the region due to the current economic conditions.

The SPP RTO conducted a 2010 SPP Stability Study for the 2011 light load case (Spring). SPP RTO is of the opinion that a light load case better represents a “worst case” scenario than the winter case. This assessment discusses potential events that could lead to instability within the SPP RTO footprint for NERC-defined categories (A, B, C and D) of events submitted by SPP RTO members. Events in category B, category C, and category D events were required to have mitigations plans before they were found to be stable. The SPP RTO also conducted a transient stability screening of the SPP RTO footprint on the previously mentioned light load case using generic clearing times (conservative values) based on the voltage level of the transmission line segment. Based on SPP member feedback, actual clearing times were applied and, the unstable events became a non-issue.

SPP RTO also conducted a transient stability screening of the SPP RTO footprint on the previously mentioned cases.

The Cross State Air Pollution Rule (CSAPR) adopted by the U.S. Environmental Protection Agency in July 2011, calls for Sulfur Dioxide (SO_2) and annual Nitrogen-Oxide (NO_X) reductions that begin in January 1, 2012. Due to the short time period between finalization of the rule and its effective date, SPP RTO and its members have not had time to fully assess the Rule’s impacts to individual systems or to the RTO as a whole. However, SPP performed a 2012 assessment of the CSAPR in September 2011. SPP’s reliability assessment of the EPA’s CSAPR Integrated Planning Model 4.1[253] generation dispatch indicates that the Rule could have serious, negative implications to the reliable operation of the electric grid in the SPP region. As a result, the SPP RTO and the SPP RE recommended that the EPA delay the effective date of the CSAPR for at least a year to allow time for SPP RTO and its members to investigate, plan, and develop solutions for maintaining grid reliability.

Other Region Specific Issues

SPP knows of no other Region-specific issues that could impact reliability besides those mentioned earlier in this report. SPP RTO continues to perform real-time, current day, next day, and seasonal reliability assessments for the SPP RC footprint. The results of these studies are shared with SPP RTO members and coordination occurs using these studies to prepare to operate the system reliably.

[253] EPA CSAPR Model: http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

Assessment Area Description

The Southwest Power Pool, Inc. Regional Transmission Organization (SPP RTO) region covers a geographic area of 370,000 square miles and has members in nine states: Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas. SPP's Reliability Coordinator footprint includes 29 balancing authorities and the RTO has over 48,000 miles of transmission lines. SPP typically experiences peak demand in the summer months.

SPP[254] has 64 members that serve over 15 million people. SPP's membership consists of 14 investor–owned utilities, 12 generation and transmission cooperatives, 10 power marketers, 11 municipal systems, 7 independent power producers, 4 state agencies, and 6 independent transmission companies. SPP was a founding member of the North American Electric Reliability Corporation in 1968, and was designated by the Federal Energy Regulatory Commission as an RTO in 2004 and a Regional Entity (RE) in 2007. As an RTO, SPP ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. The SPP RE oversees compliance enforcement and reliability standards development.

[254]SPP RTO can be reached at: http://www.spp.org

WECC

Introduction

Western Electricity Coordinating Council (WECC) is one of eight electric reliability councils in North America, and is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western states in between.

For the Winter Assessment, the WECC Region is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX). These subregions are used for two reasons. First, they are structured around Reserve Sharing Groups (RSG). These groups have similar demand patterns and operating practices. Second, the Western Reliability Centers collect actual demand data from the Reserve Sharing Groups. Creating the seasonal assessments using the same footprint allows for after-the-fact comparisons between demand forecasts and actual demand.

The NWPP is a winter peaking subregion with a large amount of hydro resources. Because it is winter peaking, the NWPP is the main focus of this winter assessment. The RMRG peak can occur in either the summer or the winter, and it has a large amount of coal fired generation. The SRSG and CA/MX subregions peak in the summer and the majority of their resources are gas-fired.

WECC expects to have adequate generation capacity, reserves, and transmission for the forecasted 2011-2012 winter peak demands and energy loads.

Demand

The WECC 2011-2012 winter total internal demand is forecast to be 129,485 MW and is projected to occur in December (Table 90). The forecast is based on normal weather and reflects generally adverse economic conditions. The forecast is 3.1 percent above last winter's actual peak demand that was established under generally above normal temperatures in the region.

Table 90: Winter Demand

Winter Season	Total Internal Demand (MW)	Projected/Actual Peak (Month-Year)
2011/2012 Forecast	129,485	
2010/2011 Forecast	126,498	
2010/2011 Actual	125,585	
All-Time Peak	136,592	December-2008

WECC requests Balancing Authorities (BA) in the Western Interconnection to submit forecasts with a 50 percent probability of occurrence. These forecasts generally consider various factors such as population growth, economic conditions and normalized weather so that there is a 50 percent probability of exceeding the forecast. The peak demand forecasts presented here are coincident sums of shaped hourly demands adjusted by demand forecasts provided by WECC's BAs.

Energy Efficiency (EE) programs vary by location and are generally offered by the Load Serving Entity (LSE).[255] For purposes of verification, some LSEs retain independent third parties to evaluate their programs.

Demand-side Management (DSM) programs offered by BAs or LSEs vary widely. The 2011-2012 demand forecast includes 685 MW of direct control load management, 1,332 MW of interruptible demand capability, and 199 MW of load as a capacity resource (Table 91). Direct control load management programs largely focus on air conditioner cycling programs, while interruptible demand programs are focused primarily on large water pumping operations and large industrial operations such as mining. The winter forecast DSM of 2,216 MW is 224 MW less than the DSM forecast for last winter. Approximately 43 percent of the total DSM is located in California. Each LSE is responsible for verifying the accuracy of its DSM and EE programs. Methods for verification include direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage.

Table 91: On-Peak Demand-Side Management

Demand Response Category	Winter Peak (MW)
Energy Efficiency (New Programs)	**-**
Non-Controllable Demand-Side Management	
Direct Control Load Management	685
Contractually Interruptible (Curtailable)	1,332
Critical Peak-Pricing (CPP) with Control	25
Load as a Capacity Resource	86
Total Dispatchanle, Controllable Demand Response	**2,128**
Total Demand-Side Management	**2,128**

Generation

For the peak winter month of December, WECC expects a Reserve Margin of 36.8 percent (49,891 MW), which significantly exceeds this year's supply adequacy model planning Reserve Margin of 14.6 percent. The Anticipated Capacity Resources for this winter are expected to be 177,160 MW compared to 182,845 MW for the 2010-2011 winter. The reduction in resources is largely due to revised energy limits on hydro generation. There are no firm capacity transactions with regions external to WECC included in the net capacity resources, and no significant generating units are scheduled to be out of service or retired during the 2011-2012 winter period. The following table presents the existing and potential resources through the end of the winter period (Table 92).

The projected reservoir levels for the 2011/2012 winter season are expected to be near to above normal throughout the region and hydro generation is expected to be sufficient to meet the winter peak

[255] Programs include: ENERGY STAR® builder incentive, business lighting rebate, retail compact fluorescent light bulb (CFL), home efficiency assistance, and those to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc.

demands and energy loads. Hydroelectric resources have been derated to reflect adverse hydro conditions.

Table 92: Existing and Potential Resources[256]

Resources	Existing-Certain (MW)	Existing-Other (MW)	Future-Planned & Future-Other (MW) (MW)
Conventional	123,612	-	2,653
Wind	5,115	-	872
Solar	19	-	78
Hydro	36,518	-	22
Biomass	1,327	-	57
Total Expected On-Peak Resources	**166,591**	**-**	**3,682**
Wind	-	7,606	1,222
Solar	-	642	428
Hydro	-	30,741	48
Biomass	-	136	-
Derates On-Peak	**-**	**39,125**	**1,698**
Existing-Inoperable	**-**	**-**	**-**

Capacity Transactions

Some WECC entities rely heavily on short-term power markets, generally using the Western System Power Pool (WSPP) contracts. The WSPP Agreement is a set of FERC-approved standardized power sales contracts used by jurisdictional and non-jurisdictional entities. The most commonly used WSPP contract is the Firm Capacity/Energy Sale or Exchange (Schedule C) that contains liquidated damage (LD) provisions and is heavily relied upon as the template for such transactions. These contracts do not reference specific generating units or a system of units, and LDs are the only remedy for non-delivery.

This assessment does not include firm capacity transactions with entities located in the Eastern Interconnection. However, the individual subregional resources include transfers between subregions within WECC. The subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC. The WECC resource allocation model places conservative transmission limits on paths between 20 load groupings (bubbles) when calculating the transfers between these areas. These transfers reflect a reasonable modeling expectation given the history and extensive activity of the Western markets. The subregional transfers also include plant contingent transfers from one subregion to another. These plant contingent transfers usually have transmission rights associated with them. Most BAs are associated with one of the three RSGs within WECC. These RSGs do not cross the WECC regional boundary and do not rely on outside assistance from other regions for emergency imports.

Transmission

WECC and subregional entities have processes in place to assess generation deliverability. WECC staff prepares an annual Power Supply Assessment (PSA)[257] that is designed to identify major load zones

[256] February 2012.

[257] WECC Power Supply Assessment

within the region that may experience load curtailments due to physically-constrained paths and internal resource limitations. In addition, extensive operating studies are prepared that model the transmission system under a number of load and resource scenarios, and operating procedures are developed to maintain safe and reliable operations. Also, major power system operators have internal processes for identifying and addressing local area resource limitations, and independent grid operators have formal procedures for obtaining reliability must-run capability, including voltage support capability, for resource-constrained areas. All related WECC transmission and transformer upgrades and additions are shown below (Table 93 and Table 94).

Table 93: WECC Transmission System Additions and Upgrades[258]

Subregion	Project Name	Status	Projected In-Service Date	Voltage (kV)	Line Length (Circuit Miles)
CAMX	Palm Springs-Coachella	In-Service	4/1/2011	230	0.8
CAMX	Oakland "X"-Oakland "C"	In-Service	5/1/2011	115	3.7
CAMX	Mira Loma-Vincent (6b)	In-Service	6/1/2011	500	5
CAMX	Mira Loma-Vincent (7b)	In-Service	6/1/2011	500	16
CAMX	Central-Sycamore #1	In-Service	7/1/2011	230	28
CAMX	Central-Sycamore #2	In-Service	7/1/2011	230	28
CAMX	Monterey Park-Orange	Under Construction	9/1/2011	500	40
CAMX	Sanger-Reedley	Under Construction	10/1/2011	115	20
CAMX	Cressey-Gallo	Under Construction	10/1/2011	115	12
CAMX	IV-Central	Under Construction	11/1/2011	500	91
CAMX	Lincoln-Rio Oso	Under Construction	12/1/2011	115	11
NWPP	Rapids-South Nile	In Service	6/1/2011	115	6
NWPP	Sedro Woolley-Snohomish	Under Construction	10/1/2011	230	38.5
NWPP	Sumner-Puyallup	Under Construction	11/1/2011	115	3
NWPP	McKenzie - Wenatchee Tap	Under Construction	12/1/2011	115	10.5
RMPA	Fort St.Vrain - Fordham	Under Construction	11/1/2011	230	21
RMPA	Baculite Mesa-West Station	Under Construction	12/1/2011	115	14
RMPA	Reunion-Prairie Center	Under Construction	12/1/2011	115	5
SRSG	Alamogordo-Holloman	In Service	5/1/2011	115	5
SRSG	Sandario/Brawley-Sandario	In Service	6/1/2011	115	0.6
SRSG	Saguaro-North Loop/Adonis	In Service	6/1/2011	115	8.5
SRSG	Valencia-Black Mountain	In Service	6/1/2011	115	2.6
SRSG	Stirling Mountain-Northwest	Planned	1/1/2012	230	41

[258] 100 kV and above; April 2011 – February 2012.

Table 94: WECC Transmission System Additions and Upgrades[259]

Subregion	Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	Projected In-Service Date	Description/Status
CAMX	Rancho Mission Viejo	138	12	8/1/2011	In-Service
CAMX	Mountainfour	115	34.5	10/1/2011	In-Service
CAMX	Whirlwind	500	230	1/1/2012	Under Construction
NWPP	Canyon	230	115	4/1/2011	In-Service
NWPP	Thorne	115	60/12.5	6/1/2011	In-Service
NWPP	Selkirk	500	230	9/1/2011	In-Service
NWPP	Colstrip	230	115	10/1/2011	Under Construction
NWPP	Great Falls	230	115	11/1/2011	Under Construction
NWPP	Twin Lakes	230	138	11/1/2011	Under Construction
RMPA	Fordham T1	230	115	11/1/2011	Under Construction
RMPA	Fordham T2	230	115	11/1/2011	Under Construction
RMPA	Erie	230	115	12/1/2011	Under Construction
SRSG	Abel	230	69	5/1/2011	In-Service
SRSG	Rio Puerco	345	115	5/1/2011	In-Service
SRSG	Tortolita	500	138	5/1/2011	In-Service
SRSG	Harry Allen #3	345	230	6/1/2011	In-Service

The transmission system is considered adequate for all projected firm transactions and significant amounts of economy energy transfers. Reactive Reserve Margins are expected to be adequate for all expected peak load conditions in all areas. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems.

Operational Issues

WECC does not expect any major scheduled generating unit outages, transmission facility outages, or unusual operating conditions that would adversely impact reliable operations during the 2011/2012 winter season. The BA's and Planning Authorities coordinate the planning of long range scheduled maintenance outages. This assures that there is sufficient generation availability during scheduled transmission outages and that there is sufficient transmission availability during scheduled generation outages to access other resources.

No environmental or regulatory restrictions have been reported that are expected to adversely impact reliability. In order to provide sufficient operating flexibility, the integration of wind generation continues to require modifications to the processes by which system operators dispatch generation resources. For example, the Bonneville Power Administration has implemented a renewable generation curtailment program that may be activated under certain light-load conditions. However, WECC staff does not anticipate reliability issues related to renewable generation during minimum demand periods and does not anticipate reliability issues related to high levels of demand response resources.

Reliability Assessment

For the winter assessment, WECC staff requested information from its BAs about any studies they have performed for the winter assessment period. WECC staff also requests that BAs update any applicable

[259] 100 kV and above; April 2011 – February 2012.

data (actual loads, forecasts, outages, future and existing resource status changes) that have been previously submitted to WECC. The submitted information and data is then reviewed and compiled into the resulting resource assessment for the WECC region and subregions.

The loads and resources, for WECC and each of the subregions, are compared against the target Reserve Margins that were developed for WECC's PSA and NERC's Long Term Reliability Assessment[260] (LTRA). The target Reserve Margins were developed using a Building Block method for developing Planning Reserve Margins (PRM). The Building Block approach has four elements: Contingency Reserves, regulating reserves, reserves for additional forced outages, and reserves for 1-in-10 weather events. The Building Block values were developed for each BA and then aggregated by subregions and the entire WECC for the PSA, LTRA and the seasonal assessment analyses. The aggregated winter season PRM target for WECC is 14.6 percent. This Reserve Margin may be lower or higher than some of the state, provincial or LSE requirements within WECC, but was developed specifically for use in the aforementioned assessments.

Regional and Subregional Reserve Margins are shown below (Table 95). The Anticipated Resources (AR) column includes the *Existing-Certain* and Net Firm Transactions plus *Future-Planned* resources and associated adjustments to potential transactions. The Prospective Capacity Resources column includes the AR values plus scheduled maintenance and transmission-limited capability.

Table 95: Region and Subregional Reserve Margins

Subregion	2011/2012 Winter Reserve Margins		
	Target	Anticipated Resources	Prospective
WECC Total	14.6%	36.8%	36.8%
CAMX	11.0%	50.9%	50.9%
NWPP	16.7%	18.3%	18.3%
RMRG	15.7%	65.6%	65.6%
SRSG	13.9%	68.6%	68.6%

Transmission Providers use the method and criteria contained in the applicable reliability standards including WECC Standard TOP-STD-007-0- Operating Transfer Capability and FAC-012-1-Transfer Capability Method.

Operating studies are reviewed to assure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach. On the basis of these ongoing activities, transmission system reliability within the Western Interconnection is expected to meet NERC and WECC standards.

WECC staff does not analyze possible fuel supply interruption. However, these types of studies are performed by the individual LSEs and BAs within the region, and no fuel supply related issues have been reported to WECC. Historically, coal-fired plants have been built at or near their fuel source and

[260] NERC Long Term Reliability Assessment

generally have long-term fuel contracts with the mine operators, or are the mine owners. Gas-fired plants are historically located near major load centers and rely on relatively abundant western gas supplies. Many of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel. However, WECC does not require verification of the operability of the backup fuel systems and does not track onsite backup fuel inventories. Most of the newer generators are strictly gas-fired plants.

Some WECC entities have taken steps to mitigate possible fuel supply vulnerabilities through obtaining long-term, firm transport capacity on gas lines, having multiple pipeline services, natural gas storage, back-up oil supplies, maintaining adequate coal supplies or acquiring purchase power agreements for periods of possible adverse hydro conditions. Natural gas supplies largely come from the San Juan Basin in northwest New Mexico and the Permian Basin in western Texas, from the gas fields in the Rocky Mountains, and from the Sedimentary Basin in western Canada. Individual entities may have fuel supply interruption mitigation procedures in place, including on-site coal storage facilities. Extreme winter weather during peak load conditions is not expected to have a significant impact on the fuel supply and WECC staff does not expect to experience reliability issues relating to natural gas quality.

WECC–Northwest Power Pool (NWPP)

Introduction

The Northwest Power Pool (NWPP) is one of the four subregions of WECC and is comprised of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, and Utah, portions of Northern California, and the Canadian provinces of British Columbia and Alberta. The NWPP, in collaboration with it members (20 BAs), has conducted an assessment of reliability in response to questions raised regarding the ability of the NWPP to meet the load requirements during the 2011-2012 winter. Since the NWPP is a large and diverse area of the Western Interconnection, its members face unique issues in the day-to-day coordinated operations of the system. The NWPP in aggregate is a winter peaking subregion with a large amount of hydroelectric resources.

Analyses indicate the NWPP will have adequate generation capacity and energy, required operating reserve (regulating reserve and Contingency Reserve), and available transmission to meet the forecasted firm loads for 2011/2012 winter operations, assuming normal ambient temperature and normal weather conditions.

This assessment is valid for the NWPP as a whole; however, these overall results do not necessarily apply to all sub-areas (individual members, BAs, states, and/or provinces) when assessed separately.

Historic Demand and Energy

The NWPP 2010/2011 coincidental winter peak of 60,200 MW occurred on December 30, 2010. The 2010/2011 coincidental winter peak was 94 percent of the forecast; however, the coincidental peak occurred during above normal temperature conditions. There is still a large component of electric space heating load within the NWPP. Normalizing for temperature variance (50 percent probability), the 2010/2011 coincidental peak would have been 61,200 or 95.6 percent of the forecast.

Forecasted Demand and Energy

The economic recession that began in 2007 has had an impact on the NWPP power usage and future forecasts. There has been no noticeable recovery to date. The 2011/2012 winter peak forecast for the NWPP of 61,800 MW, approximately 1,600 MW higher than 2010 actual, is based on normal weather, reflects the prevailing economic climate (stagnant), and has a 50 percent probability of not being exceeded.

The NWPP has approximately 600 MW of interruptible demand capability and load management. In addition, the load forecast incorporates any benefit (load reduction) associated with DSM resources, not controlled by the individual utilities. Some of the entities within the NWPP have specific programs to manage peak issues during extreme conditions. Normally these programs are used to meet the entities' operating reserve requirements and have no discernable impacts on the projected NWPP peak load.

Under normal weather conditions, the NWPP does not anticipate dependence on imports from external areas during winter peak demand periods. However, if lower-than-normal precipitation were to occur, it may be extremely advantageous to maximize the transfer capabilities from outside the NWPP to reduce reservoir drafts.

Resource Assessment

Approximately 60 percent of the NWPP resource capability is from hydroelectric generation. The remaining generation is produced from conventional thermal plants and miscellaneous resources, such as non-utility owned gas-fired cogeneration or wind. The existing and planned resources through the end of the 2011/2012 winter period are shown below (Table 96).

Table 96: Existing and Potential Resources – NWPP

Resources	Existing-Certain (MW)	Existing-Other (MW)	Future-Planned & Future-Other (MW) (MW)
Conventional	37,840	-	749
Wind	4,171	-	540
Solar	-	-	-
Hydro	30,077	-	22
Biomass	877	-	30
Total Expected On-Peak Resources	**72,965**	**-**	**1,341**
Wind	-	4,305	116
Solar	-	-	19
Hydro	-	22,083	5
Biomass	-	13	-
Derates On-Peak	**-**	**26,401**	**140**
Existing-Inoperable	**-**	**-**	**-**

Hydroelectric Capability – Northwest power planning is done by sub-area. Idaho, Nevada, Wyoming, Utah, British Columbia and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington and western Montana) coordinates the operation of its hydroelectric resources to serve its demand. The Coordinated System hydro operation is based on critical water planning assumptions (currently the 1936-1937 water-years). Critical water in the Coordinated System equates to approximately 11,000 MW (average) of firm energy load carrying capability, when reservoirs start full. Under Average water year conditions, the additional non-firm energy available is approximately 3,000 MW (average).

The Coordinated System hydro reservoirs refilled to approximately 95 percent of the Energy Content Curve by July 31, 2011.

Sustainable Hydroelectric Capability – Operators of the hydro facilities maximize the hydrology throughout the year, while assuring all competing purposes are evaluated. Although available capacity margin at time of peak can be calculated to be greater than 20 percent, this can be misleading. Since hydroelectric generation can be limited due to conditions (either lack of water or imposed restrictions), the expected sustainable capacity must be determined before establishing a representative capacity margin. In other words, the firm energy load carrying capability (FELCC) is the amount of energy that the system may be called on to produce on a firm or guaranteed basis during actual operations. The FELCC is highly dependent upon the availability of water for hydroelectric generation.

The NWPP has developed the expected sustainable capacity based on the aggregated information and estimates that the members have made with respect to their own hydroelectric generation. Sustainable capacity is for periods of at least greater than two-hours during daily peak periods, assuming various conditions. This aggregated information yields a reduction for sustained capability of approximately 7,000 MW. This reduction is more relative to the Northwest in the winter; however, under summer extreme low water conditions, it impacts summer conditions, too.

Thermal Generation – No thermal plant or fuel problems are anticipated. To the extent that existing thermal resources are not scheduled for maintenance, thermal and other resources should be available as needed during the winter peak.

Thermal Generation and Hydroelectric Generation Integration – The diversity of the NWPP provides operational efficiencies. The northwest area of the NWPP peaks in the winter, whereas the Rocky Mountain area peaks in the summer. Also, the eastern area of the NWPP has the majority of the thermal generation, whereas the western area of the NWPP has the majority of the hydroelectric generation. This allows the maximum integration of the resources to meet the NWPP coincidental peak for both the winter and the summer. In addition, this allows the twenty BAs to maximize the use of the transmission while meeting firm customer load. The thermal generation in the east integrated with the hydroelectric generation in the west improves the total available firm energy and increases the NWPP's system reliability.

Having the flexibility to use hydroelectric generation to meet peak and based load thermal generation to meet the firm energy requirements is predicated on availability of transmission; refer to the Transmission Operating Issues below.

Wind Generation – Several states have enacted Renewable Portfolio Standards (RPS) that will require some NWPP members within the next few years to satisfy at least 20 percent of their load with energy generated from renewable resources. This may result in a significant increase in variable generation within the NWPP, creating new operational challenges that will have to be addressed. Some of the safety net programs, such as balancing resources, Contingency Reserve, and under frequency load shedding, will be re-evaluated for effectiveness.

The NWPP estimated installed wind generation capacity for the 2011-2012 winter season is approximately 8,531 MW. With the increasing variable generation, conventional operation of the existing hydroelectric and thermal resources is being impacted.

The wind generation manufactures' standard operating temperature for wind turbines range from -10° C to + 40° C (14° F to 104° F). During the winter peaking period, the temperature in the areas where the majority of the wind turbines are located can go below 14°F, leaving no capability from the wind generation during those periods.

In addition, there is a risk of over-generation in the spring and fall. When the wind and hydroelectric generation are both in high generation mode, and given the environmental constraints on dissolved gases in the river, there are times when generation may exceed load plus the ability to export.

Other Generation – Within the NWPP, there is an underground natural gas storage facility that is 100 percent full. This storage is located near many of the gas plants located in the NWPP, minimizing any effect that a regional gas problem may cause. In addition, one BA in the NWPP has an excess of 700 MW of generation that can be fired on diesel fuel.

External Resources – No resources external to the NWPP are assumed for the 2011-2012 winter season. However, one BA located in the NWPP has an exchange agreement with an entity in the California region for up to 300 MW delivered firm to the BA's system.

Transmission Assessment

Several BAs are constructing new transmission within the NWPP to address load service issues. The new transmission has low impact on the over-all transfer of power from one zone to another. No significant transmission lines are scheduled to be out-of-service during the 2011/2012 winter season.

Constrained paths within the NWPP are known and operating studies modeling these constraints have been performed. As a result of these studies, operating procedures have been developed to assure safe and reliable operations.

Transmission Operating Issues

Outage Coordination – The NWPP coordinated outage (transmission) system (COS) was designed to assure that outages could be coordinated among all stakeholders (operators, maintenance personnel, transmission users, and operations planners) in an open process. This process had to assure that proper operating studies were accomplished and transmission impacts and limits known, to fulfill a requirement from the 1996 west coast disturbances that the system be operated only under studied conditions. The WECC Reliability Coordinator (RC) is involved in the outage coordination process and has direct access to the outage database.

Monthly Coordination – The process requires NWPP members to designate significant facilities that, if out of service by itself or in conjunction with another outage, will impact system capabilities. The significant facilities are defined and updated annually by the NWPP members.

The scheduled outage of these critical facilities is posted on a common database. All utilities post proposed significant outages on the COS. Outages are to be submitted to the COS at least 45 days ahead of the month they are proposed to occur so they can be viewed by interested entities. The involved entities then facilitate the NWPP coordination of all these outages.

Entities can comment on the preliminary impacts, and schedules may be adjusted to maximize reliability and minimize market impacts. If coincidental outages cause too severe of an impact, the requesting utilities work together to adjust schedules accordingly. A final outage plan is posted with estimated path capabilities 30 days prior to the month in which the outages will occur. Detailed operational transfer capability studies are then performed and the limits for each affected path are posted at least 15 days prior to the outage.

Emergency outages can be requested outside these schedule guidelines. Emergency outages are coordinated among adjacent utilities to minimize system exposure. Utilities can use the COS to assure system topology is correct for next day studies. As transmission operators increase the amount of short term outages, in addition to the significant outages, the WECC RC will be able to access the COS data base and use the final outage schedule in its real-time system analysis. This coordinated outage process has been very effective. The outage information is used by NWPP member utilities to perform system studies to maximize system reliability.

Semi-Annual Planning - Long-Range Significant Outage Planning (LRSOP) – The NWPP staff facilitates outage meetings every six months with each utility's outage coordinator to discuss proposed longer term outages. Utilities discuss anticipated outages needed for time-critical construction and periods where transmission capacity may need to be maximized. The outages are posted on the COS and on the individual companies' OASIS sites. Specific responsibilities of LRSOP include the following:

- Share outage information with all parties affected by outages of significant equipment (i.e., equipment that affects the transfer capability of rated paths). Information is shared two times each year for a minimum of a six-month period. The first meeting each year coordinates outages for July through December. The second meeting coordinates outages for January through June.
- Review the outage schedules to assure that needed outages can be reliably accomplished with minimal impact on critical transmission use.
- Outage coordinators are to post the outages on the COS within the applicable timeframes.

Next Day Operating Studies – Additional path curtailments may be required depending upon current system conditions and outages. These curtailment studies are performed by the individual path operators based on the outage schedule developed through the COS process.

According to the COS process, these studies are performed at least 15 days prior to the outage. Individual path operators and transmission owners may also perform updated next-day studies to capture emergency outage requests and current system conditions, such as generation dispatch to determine if the System Operating Limits (SOL) studies and limits are still valid. Based on these studies, additional SOL curtailments may be made by the path operators. The modified SOLs are posted on the individual transmission owner's OASIS and the WECC RC is notified.

The WECC RC also performs system studies to assure interconnected system reliability. The WECC RC performs real-time system thermal studies to evaluate current operating conditions across the entire Western Interconnection. The WECC RC is in the process of incorporating real-time voltage tools to complement the thermal analysis currently being performed. Transient stability analysis capability is planned in the future. When the WECC RC observes real-time reliability problems, they contact the path operator to discuss the issue and work on a solution.

The WECC RC will make a directive for action if there is an imminent reliability threat and the BA does not eliminate the reliability issue within an appropriate timeframe.

Voltage Stability – The WECC-1-CR System Performance Criteria, requirement WRS3 is used to plan adequate voltage stability margin in the NWPP as appropriate. Simulations are utilized to assure system performance is adequate and meets the required criteria.

Reliability Assessment

The NWPP does not have one explicit method for determining an adequacy margin. Bonneville Power Administration utilizes the Northwest Power and Conservation Council's resource adequacy standard, that establishes targets for both the energy and capacity adequacy metrics derived from a loss of load probability analysis.

Since no one method exists for the entire NWPP, we have elected to use a Reserve Margin analysis for the winter assessment. The 2011-2012 NWPP generating capability is projected to be 90,000 MW, prior to adjusting for maintenance. Based on a prior operating season, we have assumed a 1,500 MW contribution from wind resources during peak conditions. In determining a planning margin for the current winter season, one must further adjust for operating reserve requirement that is approximately 4,000 MW. At this point, based on a load of 50 percent probability not-to-exceed, the planning margin is approximately 20 percent.

A severe weather event for the entire NWPP will add approximately 6,000 MW of load, while, at the same time under extreme water restrictions, the sustained hydroelectric generation would reduce the capability by 7,000 MW. In addition, under the severe weather, wind generation is expected to be minimal. However, accounting for the severe weather event and the available generation, the NWPP will meet the peak load requirements with no additional margin.

Contingency Reserve Sharing Procedure

As permitted by NERC and WECC criteria and standards, the Operating Committee of the NWPP has instituted a Reserve Sharing Program for Contingency Reserve. Those who participate in an RSG are better positioned to meet the NERC Disturbance Control Standard because they have access to a deeper and more diverse pool of shared reserve resources. Also, an increase in efficiency is obtained since the shared reserve obligation for the group as a whole is less than the sum of each participant's reserve obligation computed separately.

By sharing Contingency Reserve, the participants are entitled to use not only their own "internal" reserve resources, but to call on other participants for assistance if internal reserve does not fully cover a contingency. The reserve sharing process for the NWPP has been automated. A manual backup process is in place if communication links are down or the computer system for reserve sharing is not functioning correctly.

The NWPP is designated as an RSG as provided under WECC Operating Reliability Criteria. Each member of the RSG submits its Contingency Reserve Obligation (CRO) and most severe single contingency (MSSC) to a central computer. The combined member CRO must be larger than the RSG MSSC. If not, then each member's CRO is proportionally increased until this requirement is met. When any RSG member loses generation, they have the right to call upon reserves from the other RSG members, as long as they have first committed their own CRO. A request for Contingency Reserve must be sent within four minutes after the generation loss, and the received Contingency Reserve can only be held for 60 minutes. A request is sent via the member's energy management system to the central computer. The central computer then distributes the request proportionally among members within the RSG. Each member may be called to provide reserve up to its CRO. Critical transmission paths are monitored in this process to ensure SOL limits are not exceeded. If a transmission path SOL is exceeded, the automated program redistributes the request among RSG members that are delivering reserve along non-congested paths. The WECC RC continuously monitors the adequacy of the RSG reserve obligation, MSSC, and the deployment of reserve. If a reserve request fails, backup procedures are in place to fully address the requirements.

Reliability Coordinator

The Reliability Coordinator is responsible for monitoring, advising, and directing action when necessary to preserve the reliability of transmission service between and within the interconnected systems of all BAs within the Western Interconnection.

Strategic Undertakings

Adequacy Response Team – The Northwest has developed an Adequacy Response Process whereby a team addresses the area's ability to avoid a power emergency by promoting regional coordination and communications. Essential pieces of that effort include timely analyses of the power situation, and communication of that information to all parties, including but not limited to utility officials, elected officials, and the general public.

Emergency Response Team (ERT) – In the fall of 2000, the area developed an emergency response process to address immediate power emergencies. The ERT remains in place and would be utilized in the event of an immediate emergency. The ERT would work with all parties in pursuing options to resolve the emergency including but not limited to load curtailment and or imports of additional power from other areas outside of the NWPP.

Largest Risk

The largest risk facing BAs within the NWPP is a significant weather event that would last over a five-day period and have temperatures at 20° F below normal. This type of an event would increase the overall NWPP load by 6,000 MW. Any additional contingency during such a weather event could cause loss of local load.

Conclusion

In view of the present overall power conditions, including the forecasted water condition, the area represented by the NWPP is estimating that it will be able to meet firm loads including the required operating reserve. Should any resources be lost to the area beyond the Contingency Reserve requirement and/or loads are greater than expected as a result of extreme weather, the NWPP may have to look to alternatives that may include emergency measures to meet obligations.

WECC – Rocky Mountain Reserve Group (RMRG)

Demand

The RMRG peak demand may occur in either summer or winter. The 2011-2012 winter coincident peak demand forecast of 9,516 MW, projected to occur in December, is 10.5 percent less than last winter's actual peak demand of 10,628 MW that occurred in February. The 2011-2012 winter peak forecast is 2.4 percent less than last winter's forecast peak demand of 9,753 MW that was projected to occur in December 2010. The expected load growth decline for the 2011-2012 winter season is largely attributed to the exceptionally cold winter period last year. The 2010-2011 winter peak demand, a new all-time peak, was 9 percent above the forecast peak demand. For the 2011-2012 winter period DSM totals 241 MW. The projected Reserve Margin for the peak month is 65.6 percent.

Generation

Hydro conditions for the 2011-2012 winter period are expected to be above normal on the Colorado River system and normal to above normal on other river drainages but some reservoir releases may be decreased due to above-normal downstream reservoir levels. The Existing and Potential resources for RMRG through the end of the winter period are shown below (Table 97).

Table 97: Existing and Potential Resources – RMRG

Resources	Existing-Certain (MW)	Existing-Other (MW)	Future-Planned & Future-Other (MW) (MW)
Conventional	14,170	-	765
Wind	-	-	-
Solar	-	-	-
Hydro	1,465	-	-
Biomass	9	-	-
Total Expected On-Peak Resources	**15,644**	**-**	**765**
Wind	-	993	250
Solar	-	8	21
Hydro	-	261	-
Biomass	-	-	-
Derates On-Peak	**-**	**1,262**	**271**
Existing-Inoperable	**-**	**-**	**-**

Transmission

The transmission system is expected to be adequate for all firm transfers and most economy energy transfers. However, the transmission path between southeastern Wyoming and Colorado often becomes heavily loaded, as do the transmission interconnections to Utah and New Mexico. WECC's Unscheduled Flow Mitigation Plan[261] may be invoked to provide line loading relief for these paths, if needed.

[261] WECC Unscheduled Flow Mitigation Plan

Operational Issues

Spring and summer had significant weather events that impacted the reliability of rail service to various plants that eventually lead to rerouting of traffic on both the Union Pacific Railroad and the Burlington Northern Santa Fe Railway. By fall, the flooding had run its course and the railroads began returning to normal operations. The slower service impacted the coal inventories at various locations. Inventories are expected to return to normal levels by winter.

Reliability Assessment

The projected Reserve Margins for the peak month of December are 58.1 percent (62.2 percent last winter) based on Existing Resources, 65.6 percent based on Existing plus Anticipated Resources, and 65.6 percent based on Existing Resources plus Anticipated Resources plus Prospective Resources. The RMRG target margin, as developed through the Building Block approach, is 15.7 percent. Generation and transmission facilities are forecast to be adequate to provide reliable electric service throughout the subregion.

WECC – Southwest Reserve Sharing Group (SRSG)

Demand

The Southwest Reserve Sharing Group (SRSG) is a summer-peaking area. The 2011-2012 winter coincident peak demand forecast of 17,166 MW, projected to occur in December, is 8 percent less than last winter's actual peak demand of 18,652 MW, which occurred in February. The 2011-2012 peak forecast is 0.4 percent less than last winter's forecast peak demand of 17,228 MW that was projected to occur in December 2010. Last winter's peak demand was higher than normal due to an unusual early February extreme cold spell. The 2010-2011 winter peak demand was 8.3 percent above the forecast peak demand. For the 2011-2012 winter, DSM is projected to total 448 MW. The projected Reserve Margin for the peak month is 68.6 percent.

Generation

Significantly above average hydro conditions are anticipated for the upcoming winter season. The Existing and Potential resources through the end of the winter period are shown below (Table 98).

Table 98: Existing and Potential Resources – SRSG

Resources	Existing-Certain (MW)	Existing-Other (MW)	Future-Planned & Future-Other (MW) (MW)
Conventional	37,777	-	1,149
Wind	209	-	-
Solar	-	-	-
Hydro	2,325	-	-
Biomass	64	-	-
Total Expected On-Peak Resources	**40,375**	**-**	**1,149**
Wind	-	375	-
Solar	-	170	308
Hydro	-	1,388	3
Biomass	-	48	-
Derates On-Peak	**-**	**1,981**	**311**
Existing-Inoperable	**-**	**-**	**-**

Transmission

Based on inter- and intra-area studies, the transmission system is considered adequate for projected firm transactions and a significant amount of economy electricity transfers. When necessary, phase-shifting transformers in the southern Utah/Colorado/Nevada transmission system will be used to help control unscheduled flows. Reactive reserve margins have been studied and are expected to be adequate throughout the area.

Operational Issues

Fuel supplies are expected to be adequate to meet winter peak demand and energy load conditions. In addition, firm coal supply and transportation contracts are in place, and sufficient coal inventories are anticipated for the winter season.

Last winter, the subregion experienced an extreme cold weather event, which caused some significant generator plant forced outages and loss of service to customers. Details regarding the event are presented in a combined NERC/FERC causes and recommendations report.[262] Entities affected by the event have taken steps to address the recommendations presented in the report.

Reliability Assessment

The projected Reserve Margins for the peak month of December are 63.8 percent (89.6 percent last winter) based on Existing Resources, 68.6 percent based on Existing plus Anticipated Resources, and 68.6 percent based on Existing Resources plus Anticipated Resources plus Prospective Resources. The SRSG target margin, as developed through the Building Block approach, is 13.9 percent. Generation and transmission facilities are forecast to be adequate to provide reliable electric service throughout the subregion.

[262] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

WECC – California / Mexico (CA / MX)

Demand

California/Mexico is a summer-peaking subregion. The 2011-2012 winter coincident peak demand forecast of 37,961 MW, projected to occur in December, is 0.8 percent above last winter's actual peak demand of 37,664 MW, which occurred in December. The 2011-2012 peak forecast is 2.3 percent less than last winter's forecast peak demand of 38,836 MW that was projected to occur in December 2010. The area's 2010-2011 winter peak demand was 3 percent less than the forecast largely due to a weaker than expected economic recovery. For the 2011-2012 winter period DSM totals 962 MW. The projected Reserve Margin for the peak month is 50.9 percent.

Generation

California is currently experiencing above-normal hydro conditions with adequate reservoir levels and it is expected that the area will have sufficient resources to meet its winter peak demand and energy requirements. The Existing and Potential resources through the end of the winter period are shown below (Table 99).

Table 99: Existing and Potential Resources – CA/MX

Resources	Existing-Certain (MW)	Existing-Other (MW)	Future-Planned & Future-Other (MW) (MW)
Conventional	38,803		68
Wind	452		294
Solar	19		-
Hydro	3,224		-
Biomass	377		27
Total Expected On-Peak Resources	**42,875**	**-**	**389**
Wind		2,217	894
Solar		464	80
Hydro		6,436	40
Biomass		75	-
Derates On-Peak	**-**	**9,192**	**1,014**
Existing-Inoperable	**-**	**-**	**-**

Transmission

Although several major constrained transmission paths have been upgraded in recent years, path constraints still exist. Significant transmission line outages planned for the winter period include:

- Midway – Vincent #3, 500-kV line out of service from October 24 to January 27;
- North Gila – Hassayampa 500-kV line out of service from November 28 to December 16;
- Table Mountain – Vaca 500-kV line out of service from January 30 to March 23; and
- Tracy – Los Banos 500-kV line out of service from February 13 to April 6.

Operational studies will be conducted prior to final approval to insure system reliability. In-area generation will be dispatched to make up for any import limitation resulting from planned maintenance outages and operating procedures are in place to manage any high loading conditions that may occur.

Operational Issues

Coordination between the California ISO and gas system operators has improved greatly in the last few years. Components of the coordination process include:

- Annual meetings in the spring with all California gas providers prior to peak operating season;
- Frequent communication with Southern California Gas when system maintenance may impact gas delivery to a power plant;
- Daily conference calls with PG&E Gas to review both gas and electric system conditions and planned system maintenance; and
- Automated communication to SoCal Gas and PG&E Gas of forecasted next day fuel consumption based on Day Ahead Market results.

All power plants in California are required to operate in accordance with strict air quality environmental regulations. Some plant owners have upgraded emission control equipment to remain in compliance with increasing emission limitations, while other owners have chosen to discontinue operating some plants. The effects of owners' responses to environmental regulations have been accounted for in the area's resource data and it is expected that environmental issues will have no additional adverse impacts on resource adequacy within the area during the upcoming winter season.

Comisión Federal de Electricidad reports that geothermal generation may be reduced during light load conditions due to minimum generation requirements of combined cycle plants.

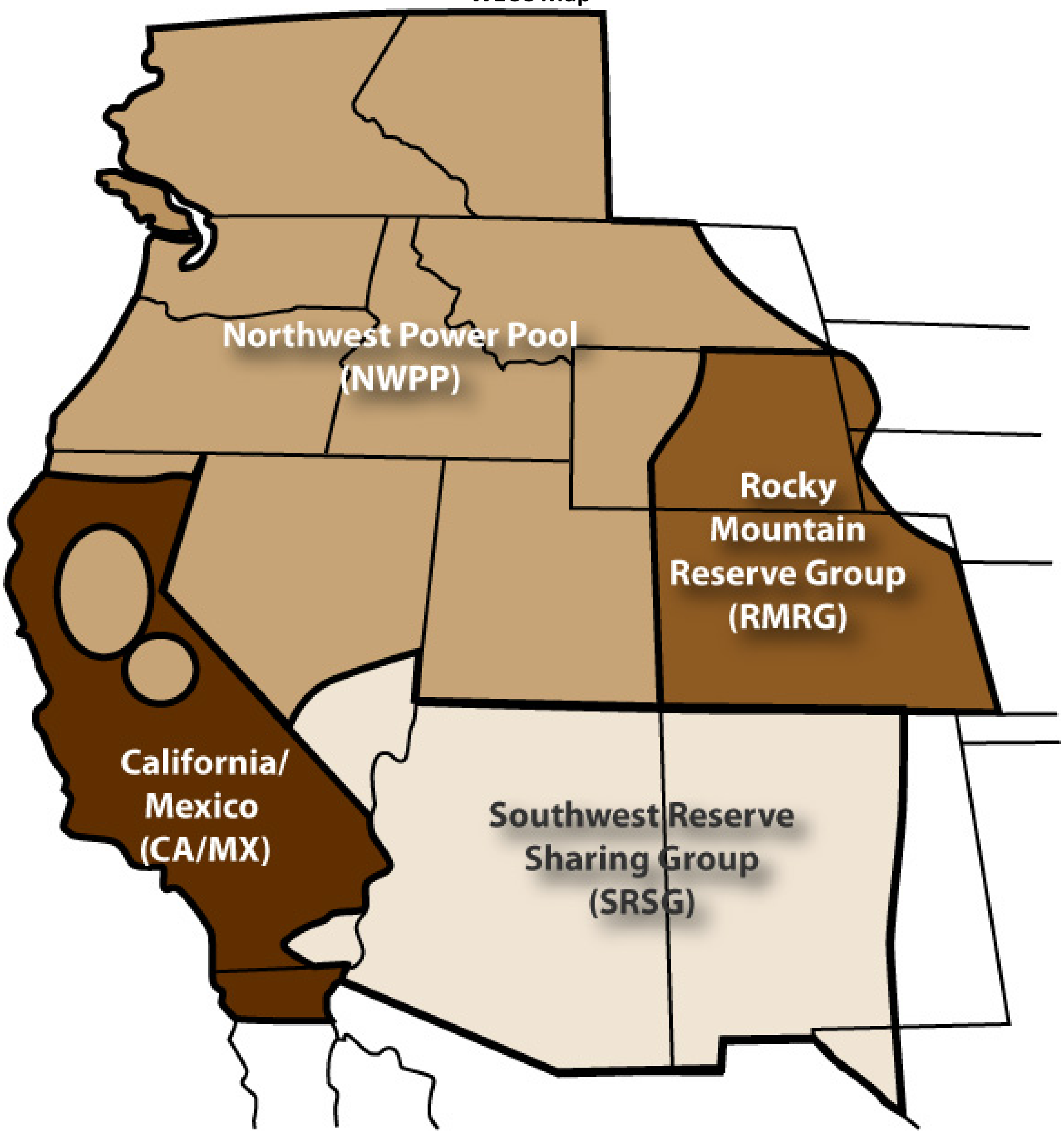
Reliability Assessment

The projected Reserve Margins for the peak month of December are 50.8 percent (70.1 percent last winter) based on Existing Resources, 50.9 percent based on Existing plus Anticipated Resources, and 50.9 percent based on Existing Resources plus Anticipated Resources plus Prospective Resources. The CA/MX target margin, as developed through the Building Block approach, is 11 percent. Generation and transmission facilities are forecast to be adequate to provide reliable electric service throughout the subregion.

Assessment Area Description

The WECC Region is a summer-peaking Region comprised of 37 Balancing Authorities. The WECC Region is nearly 1.8 million square miles with a population of approximately 81 million people, including the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of 14 Western states in between. It is the largest and most diverse of the eight NERC regional reliability organizations. Additional information regarding WECC can be found on its web site[263]

WECC Map



[263] (www.wecc.biz).

Appendix I

Recommendations of FERC/NERC Report on *Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011*

Planning and Reserves

1. Balancing Authorities, Reliability Coordinators, Transmission Operators, and Generator Owner/Operators in ERCOT and in the southwest regions of WECC should consider preparation for the winter season as critical as preparation for the summer operating season.
2. Planning Authorities should augment their winter assessments with sensitivity studies incorporating the 2011 event to ensure there are sufficient generation and reserves in the operational time horizon.
3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
4. ERCOT should reconsider its protocol that requires it to approve outages if requested more than eight days before the outage, (it should) consider giving itself the authority to cancel outages previously scheduled, and expand its outage evaluation criteria
5. ERCOT should consider modifying its procedures to (i) allow it to significantly raise the 2,300 MW responsive reserve requirement in extreme low temperatures, (ii) allow it to direct generating units to utilize pre-operational warming prior to anticipated severe cold-weather, and (iii) allow it to verify with each generating unit its preparedness for severe cold weather, including operational limits, potential fuel needs, and switching abilities.

Coordination with Generator Owner Operators

6. Transmission Operators, Balancing Authorities, and Generation Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities
7. Balancing Authorities, Transmission Operators, and Generation Owner/Operators should take the steps necessary to ensure that black start units can be utilized during adverse weather and emergency conditions.
8. Balancing Authorities, Reliability Coordinators, and Transmission Operators should require Generation Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators, and Transmission Operators should verify that the temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events.
9. Transmission Operators and Balancing Authorities should obtain from Generation Owner / Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments.
10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations can be quickly implemented in the event of severe capacity shortages.

Winterization

11. States in the Southwest should examine whether Generator/Operators ought to (should) be required to submit winterization plans, and should consider enacting legislation where necessary and appropriate.

Plant Design

12. Consideration should be given to designing (the design of) all new generating plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed.
13. The temperature design parameters of existing generating units should be assessed

Maintenance / Inspection

14. Generator Owner/Operators should ensure that adequate maintenance and inspection of its freeze protection elements be conducted on a timely and repetitive basis.
15. Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment.
16. Each Generator Owner/Operator should inspect and maintain its units' thermal insulation.
17. Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures where needed.
18. Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.
19. Each Generator Owner/Operator should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold-weather events, and that preventative action in anticipation of such events is taken in a timely manner.
20. Transmission Operators should ensure that transmission facilities are capable of performing during cold-weather conditions.

Communications

21. Balancing Authorities should improve communications during extreme cold-weather events with Transmission Owner/Operators, Distribution Providers, and other market participants.
22. ERCOT should review and modify its Protocols as needed to give Transmission Service Providers and Distribution Service Providers in Texas access to information about loads on their systems that could be curtailed by ERCOT as Load Resources or as Emergency Interruptible Load Service.
23. WECC should review its Reliability Coordinator procedures for providing notice to Transmission Operators and Balancing Authorities when another Transmission Operator or Balancing Authority within WECC is experiencing a system emergency (or likely will experience a system emergency), and consider whether modification of those procedures is needed to expedite the notice process.
24. All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency, and should consider

developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency.

Load Shedding

25. Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities, and determine the level of protection such facilities should be accorded in the event of system stress or load shedding.
26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills.

Appendix II

Conclusions and Recommendations of NERC Report on *Analysis of Power System Impacts and Frequency Response Performance: February 1-4, 2011 Texas and Southwestern U.S. Cold Snap*

Conclusions and Recommendations

1. The Analysis of controlled load interruptions resulted in the following findings:
    a. ERCOT's decisions to interrupt firm load was pivotal to maintaining the integrity of the Texas Interconnection after 05:30 CST4 on February 2nd. Controlled firm load shedding of 1,000 MW requested at 05:43 enabled ERCOT to survive the resource losses and counter the impacts of load pickup experienced near the top of the 06:00 hour. Similarly, requested shedding of an additional 1,000 MW of firm load at 06:04 assisted in recovery from the 59.57 Hz low frequency at 06:05. When the frequency showed signs of further decline at 06:23, ERCOT ordered an additional 2,000 MW of controlled firm load shedding; the total interrupted was 4,000 MW. This decision was crucial to the frequency recovery and replenishment of spinning reserves.
    b. Based on NERC's voltage stability power flow simulations, El Paso Electric's decision and amount of controlled firm load interruption was appropriate to prevent possible system voltage collapse for the loss of a single 345 kV transmission line.
    c. The controlled shedding of firm load bye Salt River Project (SRP) was reasonable to protect the Bulk Electric System. SRP did this to avoid the risk of cascading outages, maintain system frequency within acceptable bounds and replenish reserves within required times. SRP's actions were prudent and appropriate responses to the rapid series of events on the morning of February 2.
2. Frequency Response Performance during this event:
    a. Analysis of both the Eastern and Western Interconnection frequency response during the period of February 1-5, 2011 showed that, even for the large unit trips that occurred during that period, frequency response was in the range of normal performance, and frequency was well within normal frequency bounds.
3. During the cold snap, Public Service of New Mexico (PNM) experienced a number of breaker operations (none resulting in any transmission facility outages) due to low sulfur hexafluoride (SF_6) gas pressure in circuit breakers, resulting in operational challenges. SF6 breakers at PNM are designed to open before the low gas pressure compromises the insulation and arc quenching properties of the gas, which may occur during extreme cold weather if heating systems are insufficient. Recommendations to address this concern, include:
    a. SF6 breaker winterization should include tests of breaker heaters and supporting circuitry to assure that they are adequate to run the heaters and are fully functional.
    b. Heaters fed from the station DC system supported by batteries or stations with an emergency generator to supply the station service will assure breakers remain functional, should the station be without power for a period of time.
    c. Transmission Operators need to know the mode of SF6 breaker low-pressure failure. In some instances, breakers are programmed to open automatically when the pressure gets too low, while in others, breaker operation is blocked.

Appendix III: Reliability Concepts Used in this Report

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects: [264]

- **Adequacy** — is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** — is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand — demand that the end-use customer makes available to its LSE via contract or agreement for curtailment.[265]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" — the uncontrolled successive loss of system elements triggered by an incident at any location.

[264] See http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf more information about the Adequate Level of Reliability (ALR).

[265] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

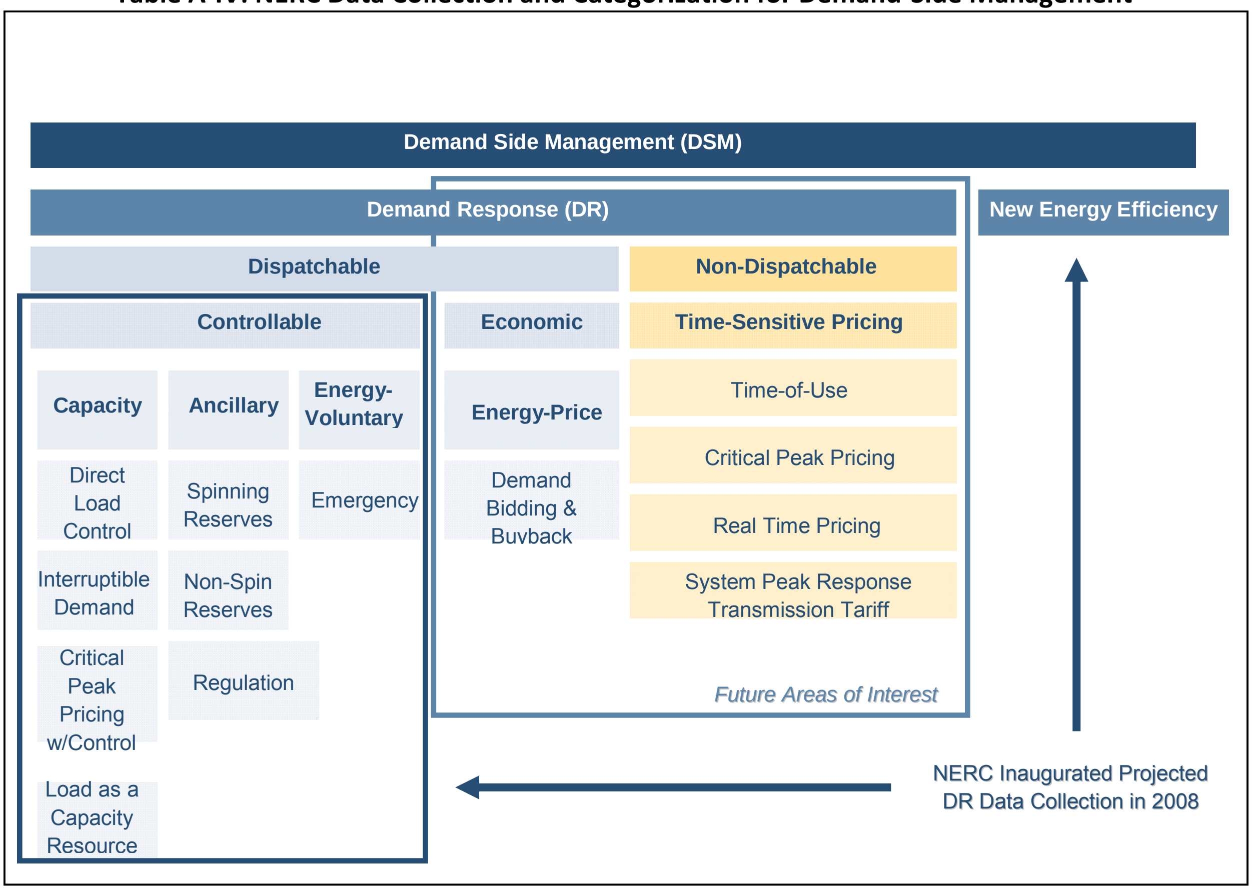
Demand Response Concepts and Categorization

As the industry's use of Demand Side Management (DSM) evolves, NERC's data collection and reliability assessments need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected Energy Efficiency programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect Demand Response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use

Note the context of these activities and programs is DSM, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. The Demand Response categories defined in *Terms Used in this Report* support the figure below.

Table A-IV: NERC Data Collection and Categorization for Demand-Side Management



Appendix IV: Terms Used in this Report

Ancillary (Controllable Demand Response) — Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Anticipated Capacity Resources – *Existing-Certain* and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports.

Anticipated Reserve Margin (%) –Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Capacity (Controllable Demand Response**) —** Demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Categories **—** *See **Existing Generation Resources, Future Generation Resources,** and **Conceptual Generation Resources***.

Capacity Margin (%) — *See **Deliverable Capacity Margin (%)** and **Prospective Capacity Margin (%)**.* Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with *Reserve Margin(s) (%)* for NERC Assessments.

***Conceptual* Generation Resources** — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

1. Corporate announcement
2. Entered into or is in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Conservation – *See* ***Energy Conservation***

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response**)** — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — *See* ***Contractually Interruptible***

Demand – *See* ***Net Internal Demand, Total Internal Demand***

Demand Bidding & Buyback (Controllable Energy-Price Demand Response**) —** Demand-side resource that enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

Demand Response — Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — 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.[266]

Dispatchable (Demand Response**)** — Demand-side resource curtails according to instruction from a control center.

Disturbance Classification Scale — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

[266] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 http://www.nerc.com/files/Glossary_2009April20.pdf

Disturbance Event – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Economic (Controllable Demand Response**)** **—** Demand-side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) **—** Demand-side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

Energy Efficiency — Permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP—002-0:

- **Level 1 — All available resources in use.**
    - Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- **Level 2 — Load management procedures in effect**.
    - Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
    - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to: Public appeals to reduce demand, Voltage reduction, Interruption of non-firm end use loads in accordance with applicable contracts, Demand-side management, and Utility load conservation measures.
- **Level 3 — Firm load interruption imminent or in progress**.
    - Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

Energy Only (Capacity) — Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Energy-Price (Controllable Economic Demand Response**) —** Demand-side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

Existing-Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[267] that is eligible to bid into a market or has been designated as a firm network resource.
3. Network Resource[268], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
4. Energy-only resources[269] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[270]
5. Capacity resources that cannot be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[271] during the period of analysis in the assessment.

***Existing-Certain* & Net Firm Transactions** – *Existing-Certain* capacity resources plus Firm Imports, minus Firm Exports. (MW)

***Existing-Certain* and Net Firm Transactions (%)** (Margin Category) – *Existing-Certain* & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources — *See* *Existing-Certain*, *Existing-Other*, *Existing, but Inoperable.*

Existing-Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future

[267] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[268] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[269] Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.

[270] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

[271] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

seasons and can be reported as zero. This includes all existing generation not included in categories *Existing-Certain* or *Existing-Other*, but is not limited to, the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other existing but out-of-service generation (that cannot be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecasted to return to service.

Existing-Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in *Existing-Certain*. This category includes, but is not limited to the following:

1. A resource with non-firm or other similar transmission arrangements.
2. Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
3. Mothballed generation (that may be returned to service for the period of the assessment).
4. Portions of variable generation not counted in the *Existing-Certain* category (*e.g.,* wind, solar, etc. that may not be available or derated during the assessment period).
5. Hydro generation not counted as *Existing-Certain* or derated.
6. Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Expected implies that a contract has not been executed, but in negotiation, projected or other. These Purchases or Sales are expected to be firm.
2. Expected Purchases and Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Firm implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also* ***Future, Planned*** *and* ***Future, Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Regulatory permits being approved, any one of the following:
   a. Site permit
   b. Construction permit

c. Environmental permit

3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future-Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future-Planned* and are not included in the *Conceptual* category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

1. Be curtailed or interrupted at any time for any reason.
2. Energy-only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the *Future, Planned* category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in category *Future, Planned* or derated.
5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future-Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or firm) or other similar resource.
2. Where organized markets exist, designated market resource[272] that is eligible to bid into a market or has been designated as a firm network resource.
3. Network Resource[273], as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[274]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

Load as a Capacity Resource (Controllable Capacity Demand Response) — Demand-side resources that commit to pre-specified load reductions when system contingencies arise.[275]

NERC's Bulk Power System Disturbance Classification Scale[276] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events.

[272] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[273] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[274] Energy only resources with transmission service constraints are to be considered in category Future, Other.

[275] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning Reserve Margins.

Each event is categorized during the triage process to help NERC and Regional Event Analysis staff to determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's Bulk Power System Event Classification Scale is designed to classify bulk power system disturbances by severity, size, and impact to the general public.

<u>Operating Security Events</u> — Operating reliability events are those that significantly affect the integrity of interconnected system operations. They are divided into 5 categories to take into account their different system impact.

- **Category 1:** An event results in any or combination of the following actions:
  a. The loss of a bulk power transmission component beyond recognized criteria,*i.e.,* single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
  b. Frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.
  c. Frequency above the High FTL more than 5 minutes.
  d. Partial loss of dc converter station (mono-polar operation).
  e. "Clear-Sky" Inter-area oscillations.
  f. Intended and controlled system separation by proper Special Protection Schemes / Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
  g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
  h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.
- **Category 2**: An event results in any or combination of the following actions:
  a. Complete loss of dc converter station.
  b. The loss of multiple bulk power transmission components.
  c. The loss of an entire switching station (all lines, 100 kV or above).
  d. The loss of an entire generation station of 5 or more generators (aggregate stations of 75 MW or higher).
  e. Loss of off-site power (LOOP) to a nuclear generating station.
  f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.
  h. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the Texas or Québec Interconnections).
  i. The planned automatic rejection of generation through special protection schemes (SPS) or remedial action schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
  j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.

[276] http://www.nerc.com/page.php?cid=5%7C252

  k. SPS/RAS misoperation.
- **Category 3:** An event results in any or combination of the following actions:
  a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
  c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.
- **Category 4:** An event results in any or combination of the following actions:
  a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.
- **Category 5:** An event results in any or combination of the following actions:
  a. The loss of load of 10,000 MW or more.
  b. The loss of generation of 10,000 MW or more.

Resource Adequacy Events — Adequacy events are divided into three categories based on Standard EOP—002-0 (Capacity and Energy Emergencies).

- **Category A1**: No disturbance events and all available resources in use.
  a. Required Operating Reserves cannot be sustained.
  b. Non-firm wholesale energy sales have been curtailed.
- **Category A2**: Load management procedures in effect.
  a. Public appeals to reduce demand.
  b. Voltage reduction.
  c. Interruption of non-firm end per contracts.
  d. Demand-side management.
  e. Utility load conservation measures.
- **Category A3**: Firm load interruption imminent or in progress.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*i.e.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-dispatchable (Demand Response**) —** Demand-side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Non-Firm implies a non-firm contract has been signed.
2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity**) —** The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Prospective Capacity Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Prospective Capacity Resources. Replaced in 2009 with *Prospective Capacity Reserve Margin (%)* for NERC Assessments.

Prospective Capacity Reserve Margin (%) – Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Prospective Capacity Resources – Deliverable Capacity Resources plus *Existing-Other* capacity resources, minus all *Existing-Other* deratings (Includes derates from variable resources, energy only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future, Other capacity resources, minus all Future, Other deratings. (MW)

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally firm.
2. Provisional Purchases and Sales should be considered in the reliability assessments.

Purchases/Imports Contracts – *See* ***Transaction Categories***

Real Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Reserve Margin Level – *See* ***NERC Reference Reserve Margin Level***

Regulation (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[277] The government of Canada has a similar definition.[278] Variable generation is a subset of Renewable Energy—See ***Variable Generation***.

Renewables — *See* ***Renewable Energy***

Reserve Margin (%) — *See* ***Deliverable Capacity Reserve Margin (%)*** *and* ***Prospective Capacity Reserve Margin (%)***. Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Resource Adequacy Events — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Sales/Exports Contracts – *See* ***Transaction Categories***

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response) Rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

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. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some

[277] http://www1.eere.energy.gov/site_administration/ glossary.html#R

[278] http://www.cleanenergy.gc.ca/faq/ index_e.asp#whatiscleanenergy

dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response**) —** Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods.

Transaction Categories (*See also* ***Firm, Non-Firm, Expected*** *and* ***Provisional)*** **—** Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region.
Example: If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Loading Relief (TLR) Levels — Various levels of the TLR Procedure from Reliability Standard IRO—006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations
- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation

- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

Transmission Status Categories — Transmission additions were categorized using the following criteria:

- Under Construction
- Construction of the line has begun
- **Planned (any of the following)**
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement
- ***Conceptual* (any of the following)**
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as "Under Construction" or "Planned"
  - Projected transmission lines that are not "Under Construction" or "Planned"

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[279] Variable generation sources which include wind, solar, ocean and some hydro generation resources are all renewable based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the bulk power system planning and operations: variability and uncertainty.

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

[279] http://www.nerc.com/files/IVGTF_Report_041609.pdf

Appendix V: Abbreviations Used in this Report

A/C	Air Conditioning
AEP	American Electric Power
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
BA	Balancing Authorities
BASN	Basin (subregion of WECC)
BCF	Billion cubic feet
BCFD	Billion cubic feet per day
CALN	California-North (subregion of WECC)
CALS	California-South (subregion of WECC)
CANW	WECC-Canada (subregion of WECC)
CFL	Compact Fluorescent Light
CMPA	California-Mexico Power Area
COI	California-Oregon Intertie
COS	Coordinated Outage (transmission) System
CPUC	California Public Utilities Commission
CRO	Contingency Reserve Obligation
CRPP	Comprehensive Reliability Planning Process (of NYISO)
DADRP	Day-Ahead Demand Response Program
dc	Direct Current
DCLM	Direct Controlled Load Management
DFW	Dallas/Fort Worth
DLC	Direct Load Control
DOE	U.S. Department of Energy
DSG	Dynamics Study Group
DSI	Direct-served Industry
DSM	Demand-Side Management
DSW	Desert Southwest (subregion of WECC)
DVAR	D-VAR® reactive power compensation system
EDRP	Emergency Demand Response Program
EE	Energy Efficiency
EEA	Energy Emergency Alert
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Agency (of DOE)
EILS	Emergency Interruptible Load Service (of ERCOT)
EISA	Energy Independence and Security Act of 2007 (USA)
ELCC	Effective Load-carrying Capability
EMTP	Electromagnetic Transient Program
ENS	Energy Not Served
EOP	Emergency Operating Procedure
ERAG	Eastern Interconnection Reliability Assessment Group

ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FCITC	First Contingency Incremental Transfer Capability
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
FP	*Future-Planned*
FO	*Future-Other*
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GGGS	Gerald Gentleman Station Stability
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool (of MAPP)
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
HVac	Heating, Ventilating, and Air Conditioning
IA	Interchange Authority
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (in Ontario)
IOU	Investor Owned Utility
IPL/NRI	International Power Line/Northeast Reliability Interconnect Project
IPSI	Integrated Power System Plan
IRM	Installed Reserve Margin
IROL	Interconnection Reliability Operating Limit
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LaaRs	Loads acting as a Resource
LCR	Locational Installed Capacity Requirements
LDC	Load Duration Curve
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss Of Load Probability
LOOP	Loss of off-site power
LRP	Long Range Plan
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
LTSG	Long-term Study Group
MAAC	Mid-Atlantic Area Council
Maf	Million acre-feet
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool

MCRSG	Midwest Contingency Reserve Sharing Group
MEXW	WECC-Mexico (subregion of WECC)
MISO	Midwest Independent Transmission System Operator
MPRP	Maine Power Reliability Program
MRO	Midwest Reliability Organization
MVA	Megavolt amperes
MVAr	Mega-VArs
MW	Megawatts (millions of watts)
MWEX	Minnesota Wisconsin Export
NB	New Brunswick
NBSO	New Brunswick System Operator
NDEX	North Dakota Export Stability Interface
NEEWS	New England East West Solution
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NOPSG	Northwest Operation and Planning Study Group
NORW	Northwest (subregion of WECC)
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NSPI	Nova Scotia Power Inc.
NTSG	Near-term Study Group
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
NYPA	New York Planning Authority
NYRSC	New York State Reliability Council, LLC
NYSERDA	New York State Energy and Research Development Agency
OASIS	Open Access Same Time Information Service
OATT	Open Access Transmission Tariff
OP	Operating Procedure
OPA	Ontario Power Authority
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
OTC	Operating Transfer Capability
OVEC	Ohio Valley Electric Corporation
PA	Planning Authority
PACE	PacifiCorp East
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PCAP	Pre-Contingency Action Plans
PCC	Planning Coordination Committee (of WECC)
PJM	PJM Interconnection
PRB	Powder River Basin
PRC	Public Regulation Commission
PRSG	Planned Reserve Sharing Group
PSA	Power Supply Assessment

PUCN	Public Utilities Commission of Nevada
QSE	Qualified Scheduling Entities
RA	Resource Adequacy
RAP	Remedial Action Plan
RAR	Resource Adequacy Requirement
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RGGI	Regional Greenhouse Gas Initiative
RIS	Resource Issues Subcommittee of NERC Planning Committee
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
ROCK	Rockies (subregion of WECC)
RP	Reliability Planner
RPM	Reliability Pricing Mode
RRS	Reliability Review Subcommittee
RSG	Reserve Sharing Group
RTEP	Regional Transmission Expansion Plan (for PJM)
RTO	Regional Transmission Organization
RTP	Real Time Pricing
RTWG	Renewable Technologies Working Group
SA	Security Analysis
SasKPower	Saskatchewan Power Corp.
SCADA	Supervisory Control and Data Acquisition
SCC	Seasonal Claimed Capability
SCD	Security Constrained Dispatch
SCDWG	Short Circuit Database Working Group
SCEC	State Capacity Emergency Coordinator (of FRCC)
SCR	Special Case Resources
SEMA	Southeastern Massachusetts
SEPA	State Environmental Protection Administration
SERC	SERC Reliability Corporation
SMUD	Sacramento Municipal Utility District
SOL	System Operating Limits
SPP	Southwest Power Pool
SPS	Special Protection System
SPS/RAS	Special Protection Schemes / Remedial Action Schemes
SRIS	System Reliability Impact Studies
SRWG	System Review Working Group
STATCOM	Static Synchronous Compensator
STEP	SPP Transmission Expansion Plan
SVC	Static VAr Compensation
TCF	Trillion Cubic Feet
TFCP	Task Force on Coordination of Planning

THI	Temperature Humidity Index
TIC	Total Import Capability
TID	Total Internal Demand
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPL	Transmission Planning
TRE	Texas Regional Entity
TRM	Transmission Reliability Margins
TS	Transformer Station
TSP	Transmission Service Provider
TSS	Technical Studies Subcommittee
TVA	Tennessee Valley Authority
USBRLC	United States Bureau of Reclamation Lower Colorado Region
UFLS	Under Frequency Load Shedding Schemes
UVLS	Under Voltage Load-Shedding
VAr	Voltampere reactive
VACAR	Virginia and Carolinas (subregion of SERC)
VSAT	Voltage Stability Assessment Tool
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index
WUMS	Wisconsin-Upper Michigan Systems

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