NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2012/2013 Winter Reliability Assessment

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RELIABILITY | ACCOUNTABILITY




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This assessment was prepared by NERC in its capacity as the Electric Reliability Organization[1] and provides an independent view of the 2012/2013 winter reliability outlook for the North American BPS,[2] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy and operating reliability, as well as an overview of projected seasonal electricity demand for individual assessment areas.

Additional inquiries regarding the information, data, and analysis in this seasonal assessment may be directed to the NERC Reliability Assessment Staff:

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[1] 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."

[2] BPS reliability, as defined in the *How NERC Defines BPS Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) of North America.[3,4] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[5]

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

NERC Regional Entities

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

NERC Regional Entities Map

NERC Assessment Areas Map

NERC prepares seasonal and long-term assessments of the overall reliability and adequacy of the North American BPS, which is divided into 26 assessment areas, both within and across the eight Regional Entity boundaries, as shown by the corresponding table and maps above.[6] To prepare these assessments, NERC collects and consolidates data from the eight Regional Entities, including forecasts for on-peak demand and energy, demand response, resource capacity, and transmission projects. The use of this bottom-up approach accounts for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The information is analyzed to identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the BPS to meet future demand. Reliability assessments are developed with the intention of informing industry, policy makers, and regulators and to aid NERC in achieving its mission—to ensure the reliability of the North American BPS.

[3] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[4] 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.

[5] 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 British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in 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 and enforceable in that jurisdiction.

[6] Assessment area boundaries are included in Appendix IV of this assessment.

Table of Contents

EXECUTIVE SUMMARY **1**

2012/2013 WINTER SEASON KEY FINDINGS **2**

PROJECTED DEMAND, RESOURCES, AND RESERVE MARGINS **15**

Regional Reliability Assessments – Summary 17

ERCOT 18

FRCC 21

MISO 24

MRO-Manitoba Hydro 27

MRO-MAPP 30

MRO-SaskPower 33

NPCC Summary 36

NPCC-Maritimes 37

NPCC-New England 40

NPCC-New York 44

NPCC-Ontario 47

NPCC-Québec 50

PJM 53

SERC-E 56

SERC-N 59

SERC-SE 62

SERC-W 65

SPP 68

WECC 71

APPENDIX I: ESTIMATED DEMAND, RESOURCES, AND RESERVE MARGINS **74**

APPENDIX II: ABBREVIATIONS USED IN THIS REPORT **76**

APPENDIX III: RELIABILITY ASSESSMENT SUBCOMMITTEE ROSTER **78**

Executive Summary

For the 2012/2013 winter operating period (December 1, 2012 through February 28, 2013), all of the assessment areas are projecting sufficient resources to meet winter peak demands.

The three key findings highlight either a common theme across North America or region-specific challenges:

- Planning Reserve Margins Sufficient to Accommodate Normal Winter Weather
- Extreme Winter Weather in Northeast Could Lead to Increased Gas-Fired Generator Outages
- Improved Winterization in the Southwest

Additional highlights of the report include:

- The NOAA 3-month winter outlook (December-February) lacks a strong signal for extreme cold. With the exception of Florida, NOAA predicts average or above average temperatures. Seasonal weather forecasts from Environment Canada show similar (average) predictions.
- NERC-wide, projected anticipated resources have increased by 14.9 GW since the 2011/2012 winter season. Peak demand is forecast to decline by 5.9 GW NERC-wide, as economic conditions impact electricity demand.
- The western U.S. experienced a relatively warm and dry 2012 summer, resulting in further deterioration of the winter snow pack and corresponding reservoir drawdown's. Drought conditions are also persistent in some areas of WECC. It is expected that the reduced river flows will result in increased thermal-based energy generation, but this will not significantly affect the ability to meet peak demand and no other issues of resource adequacy have been identified by WECC for this winter.
- Natural gas working inventories are approximately 136 billion cubic feet (Bcf) above levels recorded in October 2011. No other fuel delivery issues are noted by assessment areas due to large on-site stocks of coal supplies.

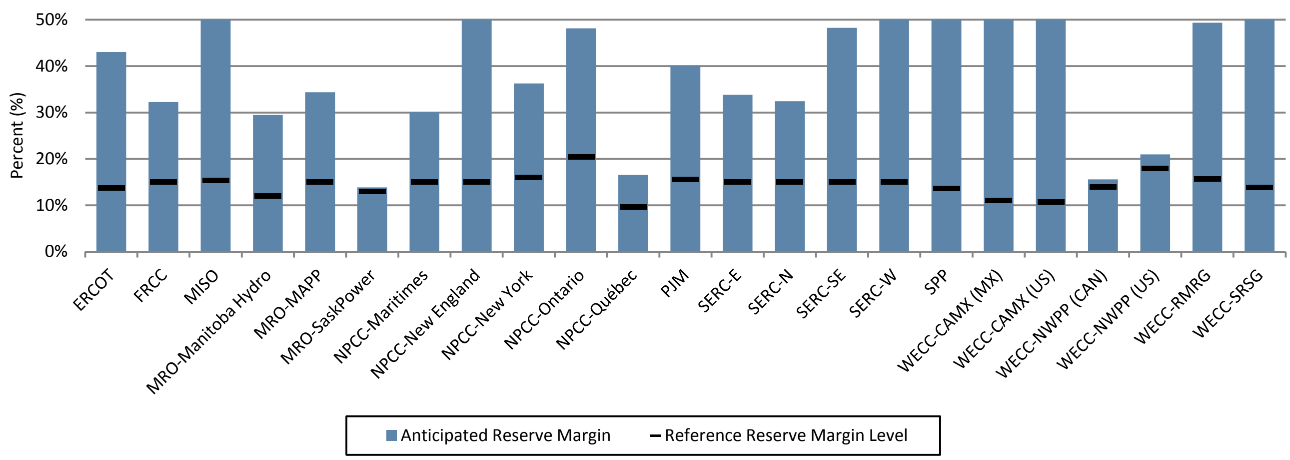
The NERC Winter Reliability Assessment has traditionally focused on the evaluation of resource adequacy and the preparations to meet peak demands for winter-peaking areas. However, the growth in natural gas demand within the electric sector has important implications on electric reliability. Increased dependence on natural gas for generating capacity has increased the need for all gas customers, as well as policy makers, to focus more sharply on the interaction between the electric and gas industries. Most importantly, in the coming years the Winter Reliability Assessment will become a valuable tool to track and assess how areas across North America will incorporate fuel dependency risks into their seasonal plans and capacity assessments. This is a vital step for NERC to understand how potential fuel interruptions and/or curtailments will be mitigated as well as understanding the assumptions for generation availability.

2012/2013 Winter Season Key Findings

Planning Reserve Margins Sufficient to Accommodate Normal Winter Weather

The North American electric industry is projecting sufficient availability of resources to serve projected peak demand during the 2012/2013 winter operating season (December 1, 2012 through February 28, 2013). Figure 1 shows the reserve margins for the peak demand month (which varies for each assessment area) for the 2012/2013 winter operating season. Because a majority of the NERC Assessment Areas experience peak demand during the summer, Anticipated Reserve Margins exceed NERC Reference Margin Levels for all assessment areas. For the winter assessment, focus is generally drawn to the winter-peaking areas in Canada (with the exception of Ontario) and the northwest. For these areas, sufficient generation is expected. From a NERC-wide perspective, projected anticipated resources have increased by 14.9 GW since the 2011/2012 winter season.[7] Peak demand is forecast to decline by 5.9 GW NERC-wide compared to last year, as economic conditions impact electricity demand.[8]

Figure 1: NERC-Wide 2012/2013 Winter Peak Reserve Margins



Eight of 23 assessment areas throughout North America are forecast to experience substantial reductions (-3.7 percent) in peak demand compared to a year earlier. Compared to the 2011/2012 winter forecast (issued in November 2011), SERC-N, MISO,[9] and SPP experience the most significant drop in peak demand of 2,042 MW, 4,909 MW, and 5,279 MW, respectively.[10] Several winter-peaking assessment areas, including MRO-Manitoba Hydro, NPCC-Maritimes and NPCC-Ontario, also see modest reductions in demand projections compared to the 2011/2012 winter.

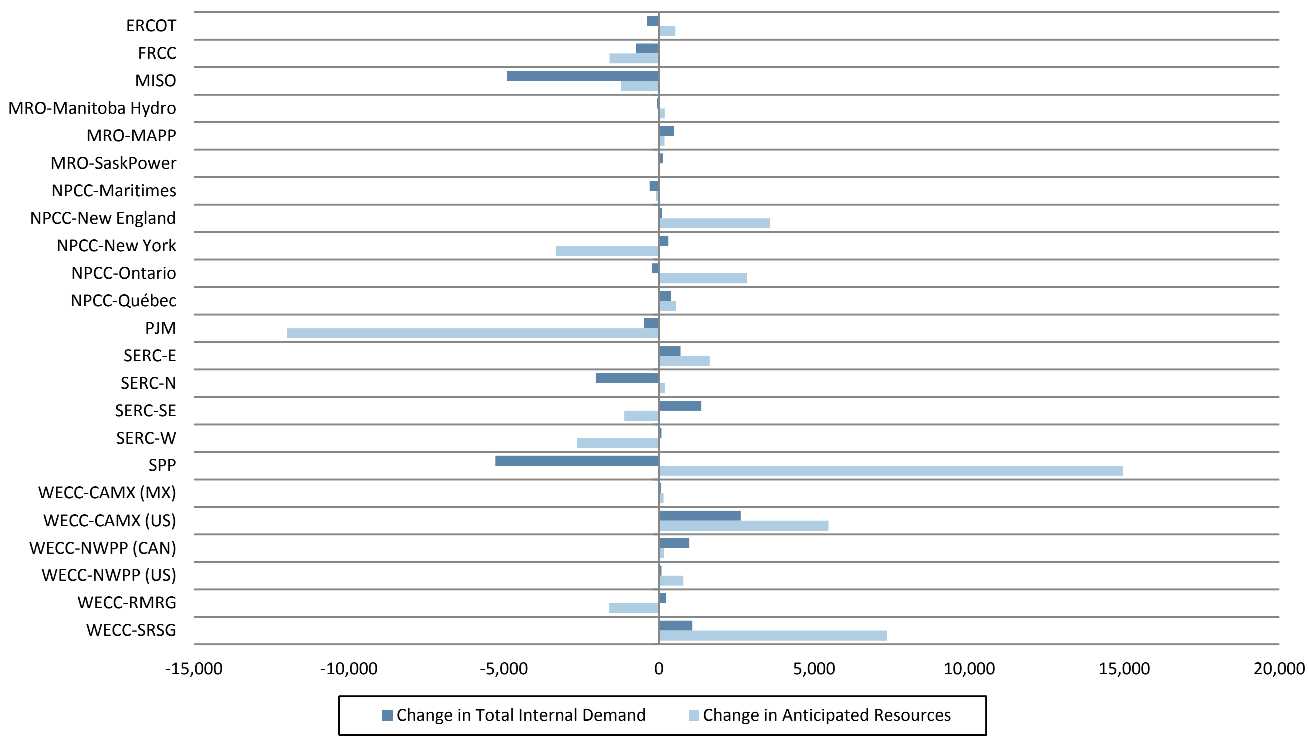
The 2011/2012 winter was the fourth warmest on record for the contiguous 48 states, resulting in only one assessment area (WECC-SRSG) experiencing an actual peak demand above forecast. According to the National Oceanic and Atmospheric Administration's (NOAA), the 2012/2013 winter outlook calls for similar above-normal temperatures across the western portion of the United States.[11] Environment Canada is predicting normal forecast temperatures for a majority of Canada for the upcoming winter as well.[12]

[7] This does not imply that 14.9 GW of capacity has been added in the past year. The increase can be attributed to capacity growth, additional resource-side demand response, generation put back into service that was unavailable during the 2011/2012 winter peak or a change in generation reporting methodology.
[8] SPP's demand forecast change is primarily due to a change in methodology. See the Demand section of SPP's assessment.
[9] MISO's membership has changed since the 2011 winter. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1st 2012, removing approximately 5,700MW of load and generation from MISO's footprint. The Entergy operating companies Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. intend to join MISO in December 2013; this is not included in the assessment.
[10] SPP's demand forecast change is primarily due to a change in methodology. See the Demand section of SPP's assessment.
[11] 2012 NOAA NWS Climate Prediction Center. College Park, MD. Updated October 18, 2012: http://www.cpc.ncep.noaa.gov/products/predictions/90day/fxus05.html.
[12] Environment Canada: http://www.weatheroffice.gc.ca/saisons/index_e.html.

Based on heating degree days, NOAA also expects the Northeast, Midwest, and South to be about 2 percent warmer than the 30-year average (1971-2000), but approximately 20 percent to 27 percent colder than last winter. Florida is projected to experience below-normal temperatures, which could impact electricity demand (the peak demand forecast for FRCC this winter is 46,864 MW, which is based on normal-weather conditions).

Most of western Canada, including WECC-NWPP (CAN) and MRO-SaskPower, are also expected to endure colder winter temperatures than compared to the 2011/2012 winter season.[13] Changes in 2012/2013 Total Internal Demand and changes in anticipated resources are shown in Figure 2.[14,15] For the winter-peaking areas, only slight changes from the prior year are expected. However, WECC-NWPP (US) is expected a significant reduction in demand when compared to last year.

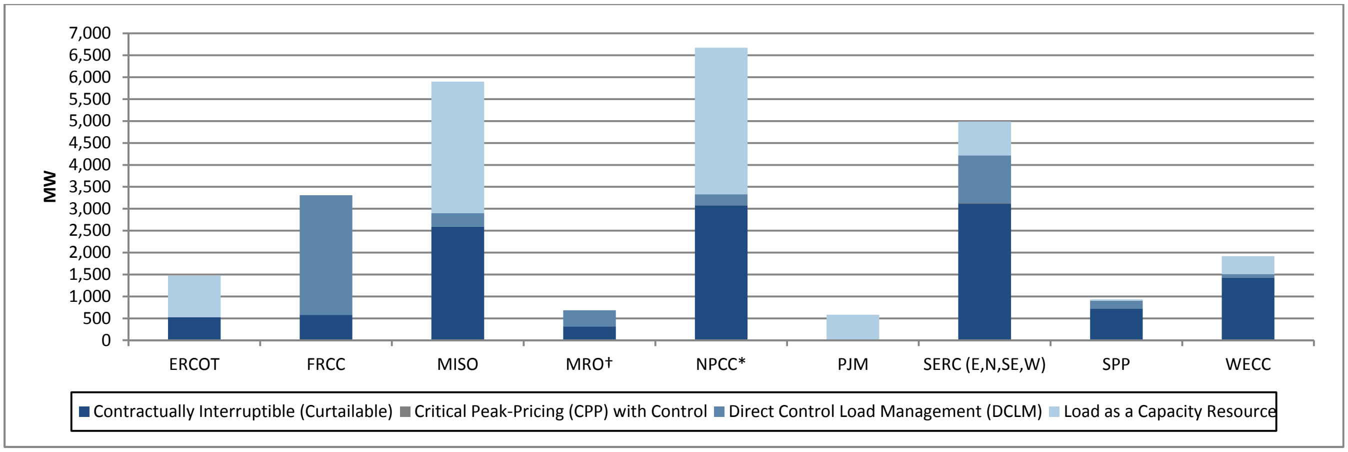
Figure 2: NERC-Wide Change in Total Internal Demand and Change in Anticipated Resources from Prior Year



Demand-side management programs, which include conservation, energy efficiency, and a variety of demand response programs, provide the electric power industry the ability to reduce peak demand and to potentially defer the need for additional future generation or transmission. Demand-side management is the term for activities or programs undertaken by a utility or an ISO/RTO with electricity end-users to influence the amount or timing of electricity they use. NERC collects controllable capacity demand response (CCDR) programs in four categories. These four types of demand response programs support reliability and are counted on to meet resource adequacy requirements (Figure 3).

Figure 3: NERC-Wide Demand Response Programs for 2012/2013

[13] Environment Canada. Monthly and Seasonal Forecasts: http://www.weatheroffice.gc.ca/saisons/index_e.html
[14] The change in SPP's Anticipated Resources is due to the way SPP is now reporting capacity resources. See SPP's Generation section of the assessment.
[15] The 12,000 MW reduction in PJM is due to boundary restructuring and maintenance outages.



Demand response (DR) programs for this winter total approximately 26,461 MW for all of NERC (Load Modifying DR: 17,138 MW and Resource-side DR: 9,323 MW). Additional flexibility is provided to operators who facilitate the use of demand response resources to support local reliability issues and other system constraints as needed. For example, demand response is being used more and more to provide ancillary services, though these programs are still in their infancy and only a small amount of capacity provides these services. Technological improvements in activation methods, as well as measurement and verification reinforce operator's confidence in demand resources in providing fast-acting response when grid conditions are stressed.

Extreme Winter Weather in Northeastern United States Could Lead to Increased Gas-Fired Generator Outages

The growth in natural gas demand within the electric sector has important implications on other gas using sectors, such as commercial and residential heating or industrial manufacturing. Increased dependence on natural gas for generating capacity has increased the need for all gas customers, from electric system planners and operators to gas pipeline operators, as well as policy makers to focus more sharply on the interaction between the electric and gas industries.

This is especially true in NPCC-New England, where gas fired capacity accounts for approximately 45 percent of the total capacity outlook.[16] For a variety of reasons, including the adoption of highly efficient combined cycle technology by the electric power industry and the emergence of shale gas, both of which have altered the relative economics of gas-fired generation, the dependence on natural gas by the electric power sector has increased significantly.

Figure 4: New England Capacity Mix for the 2012/2013 Winter Season

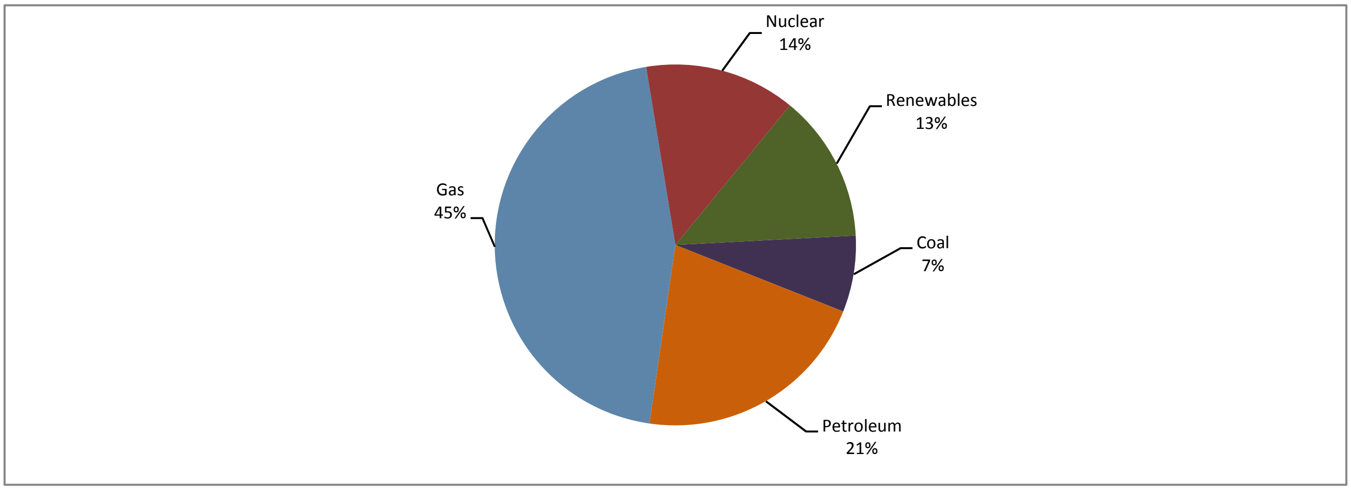
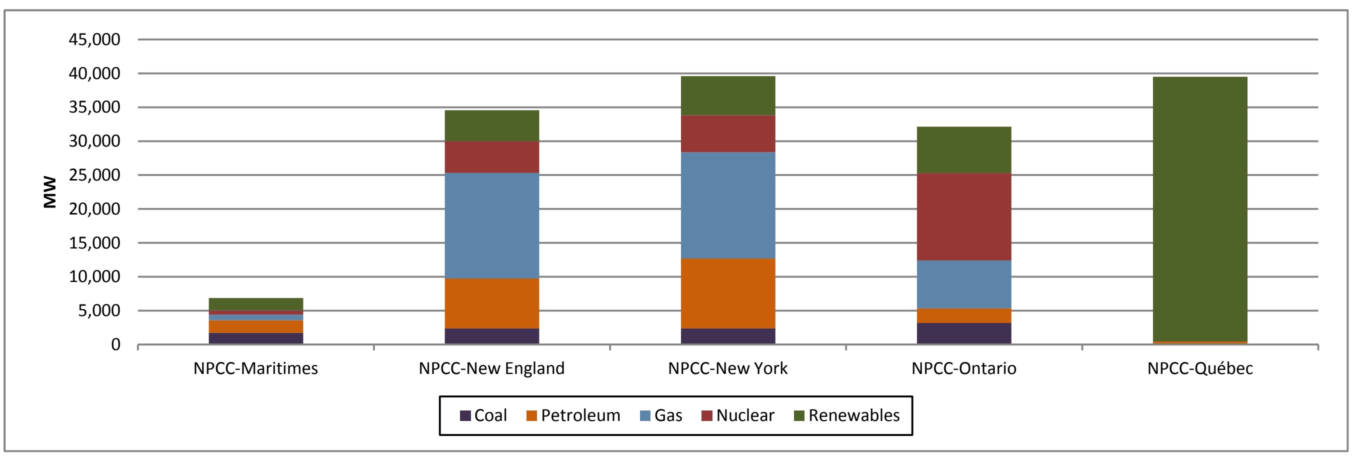


Figure 5: NPCC Subregions – Capacity Mix for the 2012/2013 Winter Season



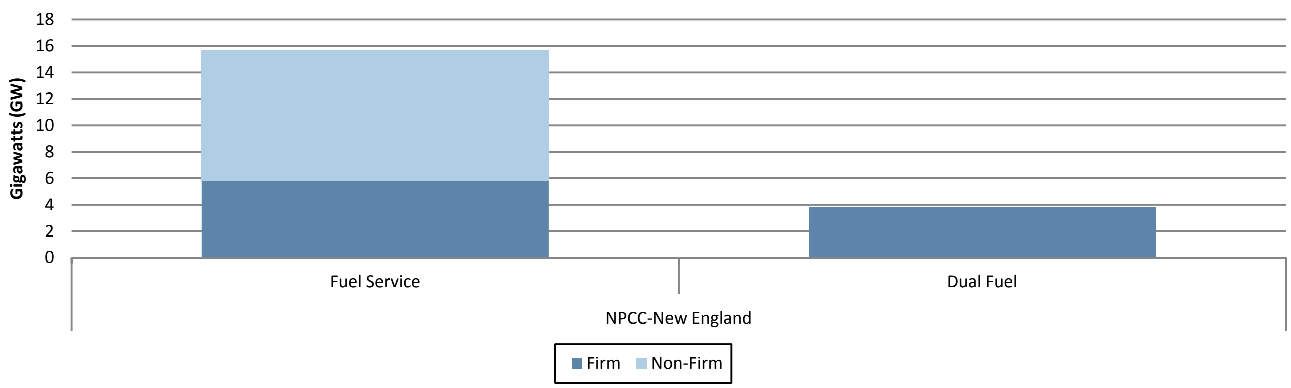
Cold weather also drives demand for natural gas. A milder than expected winter (similar to the 2011/2012 winter operating season) could even further moderate demand for natural gas, with natural gas storage reaching all-time peak levels.

[16] 2012 Long Term Reliability Assessment, NERC, http://www.nerc.com/page.php?cid=4|61.

A colder than projected winter season would increase demand by residential consumers and power generators.[17,18] Given the high amount of domestic production and large amount of working natural gas storage, gas supplies are not expected to affect bulk power system reliability.[19]

However, with pipeline capacity constrained in the northeast this winter, the electric industry will need to carefully evaluate how a disruption in fuel transportation services could affect the gas-fired generation fleet. While many infrastructure enhancements are underway to improve constrained areas, appropriate planning, including the evaluation of different scenarios, should be completed by the Planning Coordinators prior to the start of the winter season. Proper emergency procedures are needed to ensure backup fuel is available and that generators that have dual-fuel capabilities are prepared to mitigate pipeline services losses. Information on these preparations, as well as the up-to-date status of generator capabilities, is critical to ensure system operators can posture the system to withstand or manage credible and potentially known contingencies.

Figure 6: Natural Gas Fuel Service for NPCC-New England



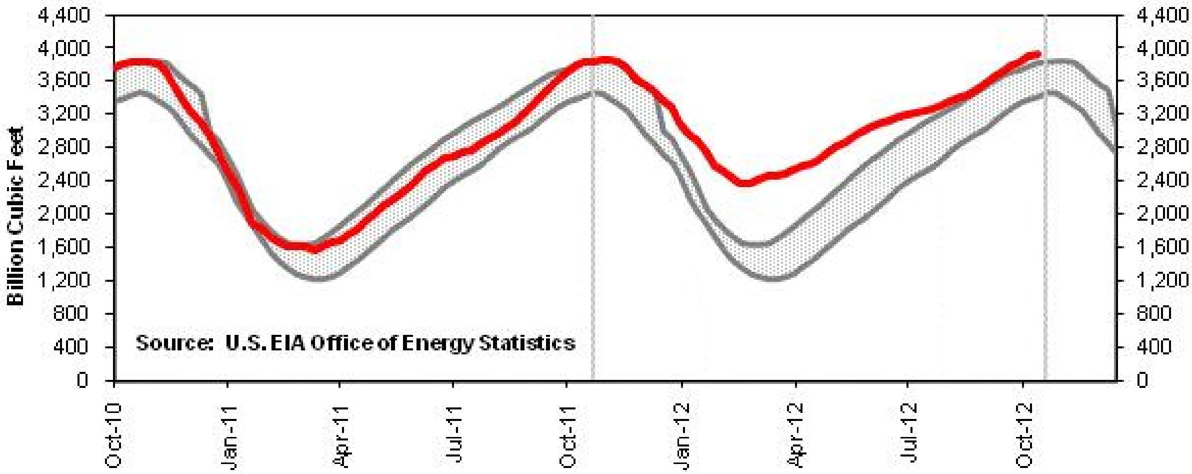
Natural Gas Production and Storage

Natural gas working inventories, ending on October 26, 2012, showed a storage value of 3.9 trillion cubic feet (Tcf). This storage value is approximately 136 billion cubic feet (Bcf), above the same point in 2011, and also above the five-year average.

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.

[17] With the exception of Florida, NOAA predicts average or above average temperatures http://www.noaanews.noaa.gov/stories2012/images/Outlook_map_temp_2b.jpg
[18] Seasonal weather forecasts from Environmental Canada show similar (average) predictions. http://www.weatheroffice.gc.ca/saisons/index_e.html#proba
[19] Natural Gas Storage is covered in more detail in the Key Highlight: Natural-Gas Fuel Deliverability Concerns for the 2012/2013 Winter Season.

Figure 7: Working Gas in Underground Storage Compared with 5-year Range[20,21]



Across the U.S., the abundance of natural gas contributed to record demand for gas by power generators during the 2011 summer period, and during the prior 2010/2011 winter season. The U.S. Energy Information Administration (EIA) expects almost no reduction in total U.S. gas consumption during the 2012/2013 winter season, since slightly lower space-heating needs are being offset by slightly higher consumption for manufacturing and power generation.

Natural gas production has fluctuated with small increases and decreases during 2012 as measured by EIA, which is in contrast to the strong upward growth seen between 2009 and 2011. Current projections by EIA indicate total natural gas production growth will slow to 2.6 Bcf/day in 2012 and 0.4 Bcf/day in 2013. The reduction in drilling activity for natural gas is offset by growth in production from liquids-rich natural gas production areas such as the Eagle Ford and wet areas of the Marcellus Shale, and associated gas from the growth in domestic crude oil production.

While NPCC-New England is not the only region in the North America facing potential gas dependency and electric reliability issues, the issues are exacerbated there because of the swift switch to gas as the fuel of choice for power and relatively small Firm pipeline capacity commitments from generators.

Most generators do not have Firm gas supply or transportation contracts and purchase remaining transportation from capacity owners—typically local distribution companies. On days of extreme winter temperatures, single-fuel, natural gas-fired capacity is at risk of being unavailable due to fuel constraints primarily because all of the capacity entitlements from Firm capacity holders—the local distribution companies—are being scheduled as contracted. This puts the area not only at risk of a curtailment event, but also due to interruptions of multiple generators. Added to that is the fact that the region is the termination point for most north- or east-bound pipes.

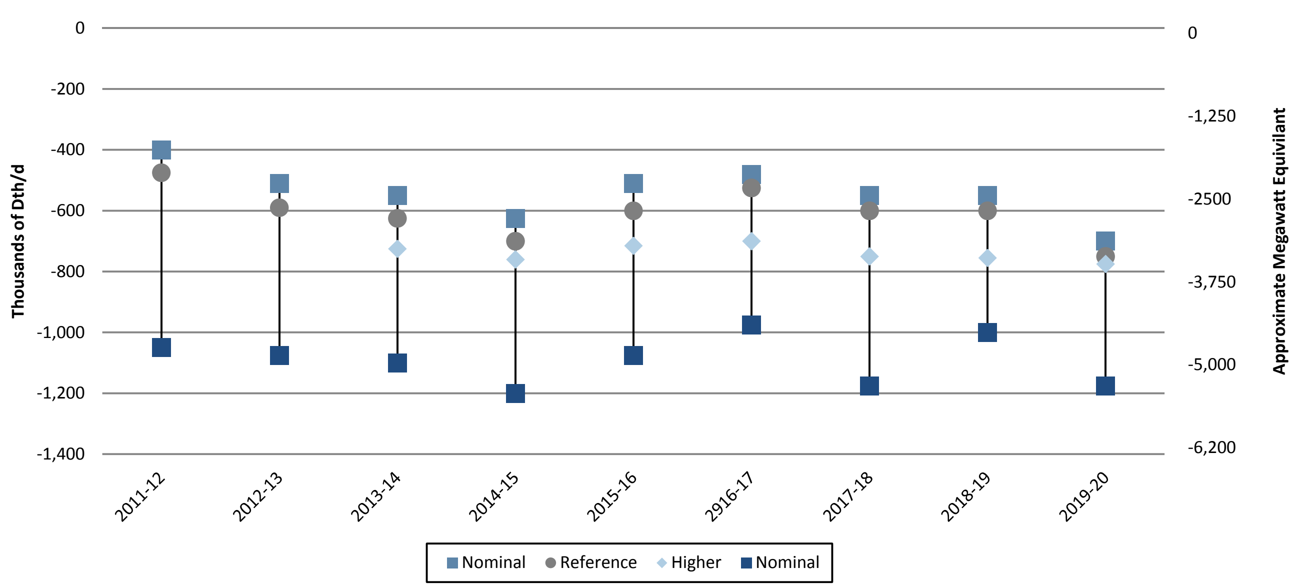
Further burdening mitigation efforts is the lack of options—no underground bulk gas storage options exist due to the geologic characteristics of New England and most of New England's gas-fired power plants are not dual-fuel capable.[22,23]

In a recent ISO-NE study, a high-level assessment was performed, determining whether the pipeline infrastructure (and available capacity) is sufficient to meet the demands of electric generators, and thus, the reliability of the bulk power system.[24] The report concluded the following for winter peak conditions:

[20] Both Y-axes represent Billion Cubic Feet of Natural Gas
[21] The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2007 through 2011. Source: Form EIA-912, "Weekly Underground Natural Gas Storage Report."
[22] The Basics of Underground Natural Gas Storage, U.S. Energy Information Administration, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html
[23] As of late October 2012, regional inventories of distillate fuel oils (i.e. jet fuel, kerosene, diesel and No. 2 fuel oil) are considerably down from their 5-year historical averages. With the restarting of several east coast refineries, this situation is expected to improve prior to winter.
[24] *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*, June 2012 :http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public.pdf

- New England's gas delivery system is already in a very tight balance on a winter design day,[25] even before any future gas demand growth is factored in.
- For the 2012/2013 winter peak, conditions could cause a capacity deficit approximately between 2,300 MW and 4,200 MW (range represents nominal to maximum Firm customer pipeline demand).
- On winter design days, supplies available to electric generators are usually below the fuel "reserve margin" (the amount of gas pipeline capacity that would be needed to supply "operating reserve" units on the power system), indicating that there is not enough supply for generators with interruptible pipeline service.
- While the probability that a gas-sector "design day" will occur is lower than the probability that a 90/10 electric load will occur, there is still a significant potential for supply shortages for gas generators with non-Firm supplies over the next ten years.

Figure 8: New England Study Shows Potential for Capacity Deficits during Winter Peak Seasons



In the fall of 2010, ISO New England (ISO-NE) launched a Strategic Planning Initiative[26] to focus the region on developing solutions to five identified risks to the continued reliable, efficient operation of the bulk power system and wholesale electricity markets.[27] One of these risks is related to increased reliance on natural gas-fired capacity. Addressing this risk has become a priority, given the reliability challenges that are already in evidence.

The continuing efforts of the New England Planning Coordinator are encouraging and provides preparation and mitigation solutions for this winter, as well as a roadmap for future enhancements; however, the amount of flexibility system operators can technically achieve in a severe weather event that affects natural gas transportation is limited.

Most of the assessment areas have indicated that there are no specific fuel deliverability issues for the upcoming winter at this time. However, the increased reliance on natural gas as one of the leading fuels used for both intermediate and peaking capacity has prompted NERC to monitor reliability considerations associated with natural gas supply and delivery.

[25] While the exact conditions used for design day planning vary among the region's individual local distribution companies, the design day criterion is generally the coldest day in the past 30 to 50 years. As a result, the local distribution companies design day standard is much more stringent than one-in-ten year extreme demand ("90/10") the BPS generally uses for its resource adequacy planning.
[26] http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/index.html
[27] DRAFT Addressing Gas Dependence (discussion paper), July 2012: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf

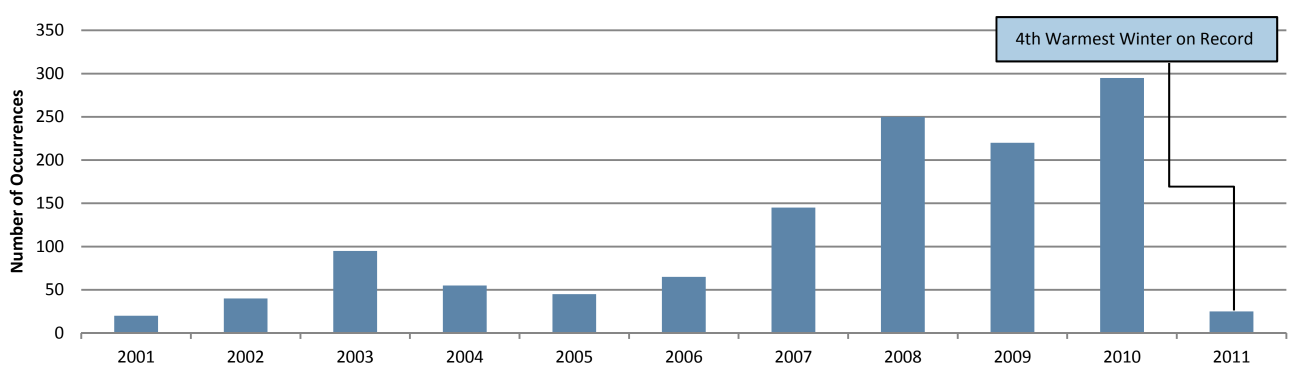
As shown in the NERC Phase I study on increasing gas dependencies, reliability challenges are more likely to occur during the winter season.

While electric generation is generally able to schedule and secure gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipelines tend to peak and Firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and/or supply disruptions, generally caused by freezing. Risks to gas wellheads, generators, and pipeline infrastructure due to freezing can expose the electric industry to significant capacity shortages.

It is important to understand that while Firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as well-head freeze-offs causing decreased gas production (a "force majeure" event), could potentially lead to common-mode failures of a significant amount of gas-fired generators. Additionally, pipeline customers who's gas use is designated as "human use" (typically, local distribution companies and some commercial customers) always receive priority over electric generation, which during emergencies and restoration efforts, can have an impact to gas-fired generation—even those that have Firm capacity rights.

Part of on-going NERC efforts includes analyzing generator past-performance through the NERC Generator Availability Data System (GADS).[28] GADS data is important in tracking gas-fired generator availability rates to determine whether trends in forced outages are increasing. Specifically, GADS data shows the capacity and number of occurrences of forced outages due to a "lack of fuel" cause code.[29] An analysis of the prior ten years shows an increasing trend in forced outages, with the exception of 2011.

Figure 9: 2001-11 GADS NERC-Wide Gas-Fired Generator Outages Due to Loss of Fuel Cause Codes



Dual fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of capacity available to meet seasonal peak demands. Ultimately, the right balance of Firm pipeline capacity, dual-fuel capabilities, and a variety of storage options will be regionally dependent. Factors such as market structure, geography, fuel-mix, and pipeline infrastructure will determine the extent of gas dependency risks as well as what solutions are available.

Improvements in system reliability can be realized from having sufficient back up and dual fuel switching capabilities available. Obstacles to achieving such benefits include State, Federal, and Provincial environmental regulations, which effectively limit the amount of oil that can be burned, and operational preparedness for these events.

Current policies and rules that regulate back-up oil use and emissions for electric generation may need to be evaluated to ensure dual fuel capability can be maintained during emergencies or other extreme conditions. Additionally, planning

[28] NERC Generating Availability Data System (GADS) : http://www.nerc.com/page.php?cid=4|43
[29] GADS Cause Codes: http://www.nerc.com/files/Appendix_B1_Fossil_Steam_Unit_Cause_Codes.pdf

processes should consider backup fuel inventories, changes in ramp and unit power capabilities, and the time requirements for fuel switch-over. Without considering this information, the amount of available dual-fuel generation projected to be available may be overstated.

As part of this plan, accurate weather forecasts are needed so that effective preparations can be made by both system operators, generators operators, and transmission operators.

Improved Winterization in the Southwest

In early February 2011, customers in the southwest region of the United States experienced unusually cold and windy weather. Lows during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. Low temperatures in Albuquerque, New Mexico ranged from 7 degrees Fahrenheit to -7 degrees over the period, compared to an average high of 51 degrees and a low of 26 degrees. Dallas temperatures ranged from 14 degrees to 19 degrees, compared to an average high of 60 degrees or above and average lows in the mid-to-upper 30s. Many cities in the region would not see temperatures above freezing until February 4. In addition, sustained high winds of over 20 mph produced severe wind chill factors.

Electric entities located within the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and the Southwest Power Pool (SPP) were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona. More details regarding the cold-snap outages are available in a joint FERC/NERC report.[30] Subsequent to the issuance of the August 2011 joint report, NERC issued eight 'Lessons Learned' reports. Those reports are available on the NERC website.[31]

Due to the Cold Snap in early February 2011, some regions have implemented modifications, enhancements, and/or new procedures for 2012/2013 winter season planning and preparation processes to anticipate extreme cold weather. Many of the regions that experience cold weather reported that they are well prepared for extreme conditions. To prepare for the 2012/2013 winter period, these regions take certain precautions, such as:

- Weatherizing their units;
- Testing for units that claim dual-fuel capability;
- Inspecting heaters and heat tracing equipment; and
- Testing black start units.

In the following Regional sections, preparations documenting the actions taken by the electric industry are highlighted.

ERCOT

ERCOT was one of the areas affected by the February 2011 cold snap. In response to this, ERCOT has sponsored a cold weather drill in response to the Feb 1-5, 2011 event. The sequence of events associated with the extreme cold events in 2011 in ERCOT is described in several presentations and reports available at the ERCOT and TRE websites.[32]

ERCOT recently submitted (August 8, 2012) Nodal Protocol Revision Request 473 (NPRR473)[33] to define the process for submission of generation resource weatherization information within the ERCOT Protocols. This NPRR creates a process to accommodate the legislatively mandated submission of generator emergency operations plans. Texas Utilities Code in Section 186.007 (f) Weather Emergency Preparedness Report states; "An electric generation entity within the ERCOT power region shall provide the entity's [emergency operations] plan to ERCOT in its entirety." ERCOT has previously requested these plans pursuant to its authority under paragraph (i) (2) (H) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance,[34] which requires ERCOT to provide "[a]n assessment of the reliability and adequacy of the ERCOT system during extremely cold or extremely hot weather conditions, including information regarding steps to be taken by power generation companies and utilities to prepare their assets for extreme weather events." Based on its authority under this statute and rule, NPRR473 proposes to 1) create a formal process for submission of emergency operations plans and plan updates and 2) recognize the confidential status of information contained in these plans.

[30] Outages and Curtailments During The Southwest Cold Weather Event of February 1-5, 2011, http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf
[31] Lessons Learned - Southwest Cold Weather Event, http://www.nerc.com/page.php?cid=5|393
[32] http://www.texasre.org/CPDL/Texas%20RE%20Event%20Observation%20-%20Feb%202%202011%20Winter%20Event-final.pdf, http://www.texasre.org/CPDL/2011-02-02%20EEA3%20Event%20Analysis-public_final.pdf, http://www.texasre.org/CPDL/2011-02-03%20Valley%20Load%20Shed%20Event%20Analysis-public_final_revised.pdf, http://www.ercot.com/content/news/presentations/2011/Severe%20weather%20events%20one-pager%202-8-11.pdf.
[33] http://www.ercot.com/mktrules/issues/nprr/451-475/473/index
[34] http://www.puc.state.tx.us/agency/rulesnlaws/subrules/electric/Electric.aspx

ERCOT also proposes to require separate submission of weatherization plans for each Generation Resource. Previously, the bulk of emergency operations plans submitted did not pertain to weatherization, and required ERCOT to sort through lengthy plans to identify parts that may or may not be intended to apply to weatherization procedures and imposed a substantial administrative burden.

ERCOT communication efforts also included the addition of a “grid status/conservation” feature to the ERCOT website similar to those on other ISO homepages.

ERCOT is also reviewing a process for semi-annual grid emergency drills, which will include government entities, industry, and other affected parties effectively extending the communication reach of ERCOT. The emergency drill process will include a crisis communication team structure currently being developed. ERCOT has implemented a change in handling overflow calls that may be a result of an emergency situation by creating a phone-bank made up of ERCOT internal staff.

ERCOT conducts qualification testing of Black Start Resources and proposed language changes in NPRR369[35] to allow a Resource Entity representing a contracted Black Start Resource to request that an alternate Generation Resource substitute for an originally contracted Black Start Resource if the alternate Generation Resource meets testing and verification under established qualification criteria to ensure Black Start Service. In addition to quarterly testing allowed by NPRR369, ERCOT may also schedule random testing to verify that qualified Black Start Resources are operable pursuant to Protocol Section 3.14.2(4).[36]

Pursuant to PUCT Substantive Rule 25.53, all generating entities in the ERCOT Region are required to weatherize their units. In addition, ERCOT is requesting information from resource owners for performing the analysis of winter extreme weather assessment. This is being done as per the new PUCT rule 25.362 (i) (2) (H) that requires ERCOT to submit a report on the generation adequacy under extreme weather conditions.

WECC

In mid-September 2011, WECC issued a winter weatherization readiness reminder to Generator Owner and Generator Operators’ primary and alternate compliance contacts. Several Balancing Authorities (BA)[37] have indicated that their prior winter season preparation procedures were adequate and that modifications, enhancements, or new winter procedures are not needed.

Some BAs, particularly those in areas most heavily impacted by the February 2011 cold weather event report implementing more rigorous plant winterization programs. Changes implemented since the 2011 event are focused on plant freeze-up prevention (e.g., heat tracing) with less apparent need for any other changes. Particularly unaffected items include communications protocols or facilities, fuel needs/switching capabilities, black start units, and emission limitations.

Power plants subject to subfreezing weather conditions are generally equipped with various plant freeze-up prevention elements. Such facilities routinely inspect those elements and make necessary repairs and/or improvements. Entities have reported that they have seasonal preparedness procedures in place that address freeze protection facility inspection and repair work and that they follow those procedures. Some of the entities in Arizona and New Mexico have reported post-2011 improvements to either the freeze protection elements or the winter preparedness procedures related to those facilities.

Operating limit testing, potential fuel need determination, and fuel switching capability tests are routine power plant owner functions. However, performing such activities during extreme cold weather conditions is not a routine activity. One summer-peaking entity reported that it does periodically perform tests during cold weather conditions to ensure plant availability. An entity in the area most severely impacted by the February 2011 cold snap reported that it undertook a

[35] http://www.ercot.com/mktrules/issues/nprr/351-375/369/index
[36] http://www.ercot.com/mktrules/nprotocols/current
[37] There are a number of Generator Owners and Generator Operators in the WECC Region that are also registered as Balancing Authorities in the NERC Compliance Registry.

review of generator unit and plant equipment temperature design limitations. It also reviewed its plant performance, including auxiliaries, during the 2011 extreme cold snap and used that information to determine which devices/equipment would need additional enhancements. This work will be completed prior to the upcoming winter season.

Entities within WECC also have established generator unit rating procedures as well as procedure for establishing near-term expected output capability. No WECC entities have reported enhancements to those procedures relative to real power output capability in advance of anticipated extreme cold weather. However, one entity in the area most severely impacted by the February 2011 cold weather event reported that it is evaluating implementing output forecasts based on forecasted weather conditions.

Several entities reported that one or more of the 2011 cold weather event lessons learned have been incorporated into their winter preparation procedures. Responses from several other entities indicate that their winter preparation procedures may be revised prior to the start of the winter season. As one might expect, the bulk of the procedural changes are concentrated in the geographic area most severely impacted by the 2011 cold weather event.

SPP

The SPP RTO footprint experiences harsh winter weather conditions that include temperatures below freezing, sleet and snow every year. As a result, generator and transmission facility owners prepare for these conditions each year.

However, several entities in the SPP RTO footprint did experience some problems during the extreme winter conditions that occurred in February 2011. As a result, SPP RTO and individual members reviewed their existing winter weather preparation plans and the Southwest Cold Weather Event recommendations and have made enhancements where needed.

To prepare generators for the winter period, beginning in late September through the month of October, SPP RTO generation owners assess their Winter Preparedness procedures. These procedures include the inspection of all heat trace equipment, windbreaks, heaters, and complete all winterization checklist procedures. If any equipment is found to be damaged or faulty, temporary freeze protection methods will be put into place until the equipment fix is completed. Safety departments also review the winter weather safety procedures for personnel and all safety equipment needed in severe winter conditions.

SPP RTO Members are required to test their generators in accordance with SPP Criteria 12,[38] which includes the periodic testing of generators operating limits and fuel switching capabilities. SPP RTO Members perform seasonal power flow studies, and while there are numerous dual fuel capable units within the SPP RTO area, there are no critical system loads dependent on a single source of generation fuel. Some RTO Members monitor a 10-day forecast issued by the National Weather Service and ensure that adequate fuel supplies are on hand to handle any extreme cold weather events that may impact delivery.

Others Areas

Regions that weren't affected by the cold snap, such as FRCC and SERC, incorporated the lessons learned and made modifications to their policies and procedures to accommodate cold-weather events.

Although FRCC does not regularly experience harsh winter weather the majority of Generator Owners and Generator Operators within the FRCC Region indicated through a Regional survey that their cold weather preparatory plans were adequate. In addition, the FRCC held a cold weather preparation meeting to review lessons learned and develop guidelines and training for winter preparation. The most common areas of improvement that have now been incorporated among owners and operators covered the flexibility of dual-fueled generators to switch between primary and alternate fuel

[38] SPP Criteria: http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20Jan.%202012.pdf

sources (e.g., natural gas or fuel oil); for the consideration of emission limitations and their impact to operations during extreme cold weather events; and the increased training of staff on new and existing processes and preparedness procedures.

In SERC-E, entities already have existing procedures in place to address potential reliability concerns. To prepare generators for the upcoming winter, entities report that various stations have existing procedures to perform inspections on heaters and heat tracing equipment each fall. Generating unit capability is measured on a regular basis to conFirm that each unit is capable of providing rated output. Any limitations are communicated promptly to entity operations staff. For those units with fuel switching capability, fuel systems are tested annually during winter months to ensure fuel switching can be accomplished. Fuel inventories are monitored and increased as necessary, to ensure an adequate supply.

Entities in the area are currently performing detailed reviews of the recommendations from the February 1-5, 2011 cold weather event and providing responses to various regulatory agencies on the evaluation of their system. Although many of the recommendations helped to reinforce plans and procedures already in place, some entities have taken additional steps to improve their plans. Entity improvements include; the testing of black start units in cold weather, providing electric service for compression stations that support gas service for generation facilities, and establishing protocol to protect this electrical supply.

Projected Demand, Resources, and Reserve Margins

Winter 2012/2013 Non-Coincident Peak

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	51,461	52,909	73,563	73,563	73,563	42.95%	42.95%	42.95%	13.75%
FRCC	43,558	46,864	58,405	57,605	58,675	34.09%	32.25%	34.71%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	5,137	5,512	6,833	6,901	7,134	33.03%	34.36%	38.89%	15.00%
NPCC-New England	21,392	22,355	35,755	35,882	35,882	67.14%	67.74%	67.74%	15.00%
NPCC-New York	24,832	24,832	33,841	33,841	33,841	36.28%	36.28%	36.28%	16.00%
PJM	130,222	130,222	182,467	182,467	182,467	40.12%	40.12%	40.12%	15.60%
SERC-E	41,647	43,150	53,348	55,737	55,789	28.10%	33.83%	33.96%	15.00%
SERC-N	43,489	45,081	57,595	57,595	63,885	32.44%	32.44%	46.90%	15.00%
SERC-SE	43,738	45,620	63,619	64,840	67,253	45.46%	48.25%	53.76%	15.00%
SERC-W	19,997	20,008	34,193	34,193	39,195	70.99%	70.99%	96.00%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,463	1,463	2,504	2,504	2,504	71.16%	71.16%	71.16%	10.70%
WECC-NWPP (US)	43,215	43,549	51,737	52,275	52,275	19.72%	20.96%	20.96%	18.00%
WECC-RMRG	9,477	9,744	13,775	14,155	14,155	45.35%	49.36%	49.36%	15.70%
WECC-SRSG	17,971	18,239	36,244	36,288	36,288	101.68%	101.93%	101.93%	13.90%
TOTAL-UNITED STATES	604,863	620,442	894,129	897,724	924,436	47.82%	48.42%	52.83%	15.00%
MRO-Manitoba Hydro	4,182	4,407	5,414	5,414	5,414	29.46%	29.46%	29.46%	12.00%
MRO-SaskPower	3,426	3,512	3,901	3,901	4,086	13.86%	13.86%	19.25%	13.00%
NPCC-Maritimes	5,076	5,246	6,607	6,607	6,607	30.17%	30.17%	30.17%	15.00%
NPCC-Ontario	22,087	22,087	31,357	32,719	33,349	41.97%	48.14%	50.99%	20.40%
NPCC-Québec	35,713	37,543	41,619	41,619	41,619	16.54%	16.54%	16.54%	9.60%
WECC-NWPP (CAN)	22,283	22,339	25,507	25,758	25,758	14.47%	15.59%	15.59%	14.00%
TOTAL-CANADA	92,767	95,134	114,406	116,018	116,833	23.33%	25.06%	25.94%	10.00%
CAMX-MX	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-MEXICO	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-NERC	**735,821**	**754,764**	**1,068,920**	**1,074,208**	**1,101,735**	**45.27%**	**45.99%**	**49.73%**	**58.30%**

December 2012

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	51,461	52,909	73,563	73,563	73,563	42.95%	42.95%	42.95%	13.75%
FRCC	34,818	37,817	58,405	56,986	58,057	67.74%	63.67%	66.74%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	5,059	5,275	6,880	6,888	7,121	35.99%	36.14%	40.75%	15.00%
NPCC-New England	20,669	21,632	35,442	35,569	35,569	71.48%	72.09%	72.09%	15.00%
NPCC-New York	24,832	24,832	33,301	33,301	33,301	34.11%	34.11%	34.11%	16.00%
PJM	126,401	126,401	182,467	182,467	182,467	44.36%	44.36%	44.36%	15.60%
SERC-E	38,607	40,143	53,378	54,718	54,770	38.26%	41.73%	41.87%	15.00%
SERC-N	39,046	40,111	57,595	57,595	63,885	47.51%	47.51%	63.62%	15.00%
SERC-SE	38,913	40,670	63,793	64,093	66,506	63.94%	64.71%	70.91%	15.00%
SERC-W	19,715	19,726	34,383	34,383	39,195	74.40%	74.40%	98.81%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,455	1,455	3,010	3,010	3,010	106.87%	106.87%	106.87%	10.70%
WECC-NWPP (US)	43,215	43,549	51,737	52,275	52,275	19.72%	20.96%	20.96%	18.00%
WECC-RMRG	9,377	9,643	12,244	12,624	12,624	30.57%	34.63%	34.63%	15.70%
WECC-SRSG	17,971	18,239	36,244	36,288	36,288	101.68%	101.93%	101.93%	13.90%
TOTAL-UNITED STATES	578,804	593,297	892,691	893,637	920,160	54.23%	54.39%	58.98%	15.00%
MRO-Manitoba Hydro	4,092	4,317	5,401	5,401	5,401	31.99%	31.99%	31.99%	12.00%
MRO-SaskPower	3,426	3,512	3,901	3,901	4,086	13.86%	13.86%	19.25%	13.00%
NPCC-Maritimes	4,739	4,894	6,574	6,574	6,574	38.73%	38.73%	38.73%	15.00%
NPCC-Ontario	21,693	21,693	30,299	31,872	32,352	39.67%	46.92%	49.13%	20.40%
NPCC-Québec	32,939	34,769	41,586	41,586	41,586	26.25%	26.25%	26.25%	9.60%
WECC-NWPP (CAN)	22,283	22,339	25,507	25,758	25,758	14.47%	15.59%	15.59%	14.00%
TOTAL-CANADA	89,172	91,524	113,269	115,092	115,757	27.02%	29.07%	29.81%	10.00%
CAMX-MX	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-MEXICO	38,191	39,187	60,386	60,466	60,466	58.12%	58.33%	58.33%	11.00%
TOTAL-NERC	**706,167**	**724,008**	**1,066,345**	**1,069,196**	**1,096,383**	**51.00%**	**51.41%**	**55.26%**	**58.30%**

Winter 2012/2013 Coincident Peak: January 2013

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	49,328	50,776	74,051	74,051	74,051	50.12%	50.12%	50.12%	13.75%
FRCC	43,558	46,864	58,405	57,605	58,675	34.09%	32.25%	34.71%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	5,137	5,512	6,833	6,901	7,134	33.03%	34.36%	38.89%	15.00%
NPCC-New England	21,392	22,355	35,755	35,882	35,882	67.14%	67.74%	67.74%	15.00%
NPCC-New York	24,832	24,832	34,347	34,347	34,347	38.32%	38.32%	38.32%	16.00%
PJM	130,222	130,222	182,467	182,467	182,467	40.12%	40.12%	40.12%	15.60%
SERC-E	41,647	43,150	53,348	55,737	55,789	28.10%	33.83%	33.96%	15.00%
SERC-N	43,489	45,081	57,595	57,595	63,885	32.44%	32.44%	46.90%	15.00%
SERC-SE	43,738	45,620	63,619	64,840	67,253	45.46%	48.25%	53.76%	15.00%
SERC-W	19,997	20,008	34,193	34,193	39,195	70.99%	70.99%	96.00%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,463	1,463	2,504	2,504	2,504	71.16%	71.16%	71.16%	10.70%
WECC-NWPP (US)	41,444	41,856	49,060	49,632	49,632	18.38%	19.76%	19.76%	18.00%
WECC-RMRG	9,477	9,744	13,775	14,155	14,155	45.35%	49.36%	49.36%	15.70%
WECC-SRSG	17,573	17,851	35,505	35,549	35,549	102.04%	102.29%	102.29%	13.90%
TOTAL-UNITED STATES	600,561	616,228	891,707	895,336	922,048	48.48%	49.08%	53.53%	15.00%
MRO-Manitoba Hydro	4,182	4,407	5,414	5,414	5,414	29.46%	29.46%	29.46%	12.00%
MRO-SaskPower	3,424	3,510	3,901	3,901	4,100	13.92%	13.92%	19.74%	13.00%
NPCC-Maritimes	5,076	5,246	6,607	6,607	6,607	30.17%	30.17%	30.17%	15.00%
NPCC-Ontario	22,087	22,087	31,357	32,719	33,349	41.97%	48.14%	50.99%	20.40%
NPCC-Québec	35,713	37,543	41,619	41,619	41,619	16.54%	16.54%	16.54%	9.60%
WECC-NWPP (CAN)	21,985	21,985	25,132	25,355	25,355	14.31%	15.33%	15.33%	14.00%
TOTAL-CANADA	92,467	94,778	114,030	115,615	116,444	23.32%	25.03%	25.93%	10.00%
CAMX-MX	35,986	37,111	57,792	58,370	58,370	60.60%	62.20%	62.20%	11.00%
TOTAL-MEXICO	35,986	37,111	57,792	58,370	58,370	60.60%	62.20%	62.20%	11.00%
TOTAL-NERC	**729,014**	**748,118**	**1,063,529**	**1,069,321**	**1,096,863**	**45.89%**	**46.68%**	**50.46%**	**58.30%**

February 2013

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins			NERC
Country / Assessment Area	Net Internal	Total Internal	Existing-Certain	Anticipated	Prospective	Existing-Certain	Anticipated	Prospective	Reference
ERCOT	43,617	45,065	71,737	71,737	71,737	64.47%	64.47%	64.47%	13.75%
FRCC	35,393	38,550	58,405	57,614	58,684	65.02%	62.78%	65.81%	15.00%
MISO	72,187	75,085	109,541	109,541	121,193	51.75%	51.75%	67.89%	15.40%
MRO-MAPP	4,994	5,335	6,834	6,902	7,135	36.85%	38.21%	42.87%	15.00%
NPCC-New England	20,891	21,854	34,536	34,663	34,663	65.32%	65.92%	65.92%	15.00%
NPCC-New York	24,832	24,832	33,841	33,841	33,841	36.28%	36.28%	36.28%	16.00%
PJM	125,061	125,061	182,467	182,467	182,467	45.90%	45.90%	45.90%	15.60%
SERC-E	38,880	40,382	53,348	55,737	55,789	37.21%	43.35%	43.49%	15.00%
SERC-N	40,355	41,520	57,596	57,596	63,886	42.72%	42.72%	58.31%	15.00%
SERC-SE	41,273	43,153	63,619	64,840	67,253	54.14%	57.10%	62.95%	15.00%
SERC-W	20,165	20,176	34,193	34,193	39,195	69.57%	69.57%	94.37%	15.00%
SPP	35,079	35,810	80,708	80,337	80,337	130.08%	129.02%	129.02%	13.60%
WECC-CAMX (US)	1,432	1,432	2,735	2,735	2,735	90.99%	90.99%	90.99%	10.70%
WECC-NWPP (US)	40,035	40,326	51,535	52,080	52,080	28.72%	30.09%	30.09%	18.00%
WECC-RMRG	9,232	9,500	14,108	14,488	14,488	52.82%	56.93%	56.93%	15.70%
WECC-SRSG	16,742	17,052	34,263	34,307	34,307	104.65%	104.92%	104.92%	13.90%
TOTAL-UNITED STATES	570,167	585,133	889,466	893,077	919,790	56.00%	56.63%	61.32%	15.00%
MRO-Manitoba Hydro	4,106	4,331	5,417	5,417	5,417	31.93%	31.93%	31.93%	12.00%
MRO-SaskPower	3,392	3,478	3,907	3,907	4,083	15.17%	15.17%	20.37%	13.00%
NPCC-Maritimes	5,023	5,199	6,613	6,613	6,613	31.66%	31.66%	31.66%	15.00%
NPCC-Ontario	21,813	21,813	30,373	31,775	32,455	39.25%	45.67%	48.79%	20.40%
NPCC-Québec	34,338	36,168	41,341	41,330	41,330	20.39%	20.36%	20.36%	9.60%
WECC-NWPP (CAN)	20,912	20,912	24,196	24,415	24,415	15.70%	16.75%	16.75%	14.00%
TOTAL-CANADA	89,584	91,901	111,847	113,457	114,313	24.85%	26.65%	27.61%	10.00%
CAMX-MX	35,080	36,232	56,433	57,009	57,009	60.87%	62.51%	62.51%	11.00%
TOTAL-MEXICO	35,080	36,232	56,433	57,009	57,009	60.87%	62.51%	62.51%	11.00%
TOTAL-NERC	**694,831**	**713,265**	**1,057,746**	**1,063,543**	**1,091,112**	**52.23%**	**53.07%**	**57.03%**	**58.30%**

Regional Reliability Assessments – Summary

The purpose of the following sections is to present the 2012/2013 winter projections for the reliability, resources, demand, and transmission infrastructure within each of the NERC Assessment Areas. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data. Resource availability and the development of expected resources are all included in the assessments and represents the capacity that is being planned to serve peak demand.

Individual assessment area details are available from NERC upon request.[39]

[39] Send requests to esd@nerc.net.

ERCOT

2012/2013 Winter Season: Assessment Area Summary

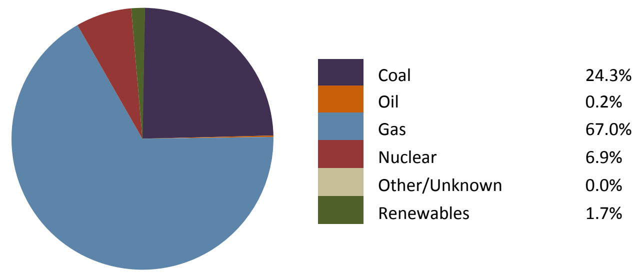
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**52,909**
Load-Modifying Demand Response	1,448
Net Internal Demand	**51,461**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	53,303
Actual Demand	50,969

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	281
Existing-Certain and Future-Planned Capacity	73,282
Anticipated Resources	**73,563**
Anticipated Reserve Margin (%)	**42.95%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**73,563**
Prospective Reserve Margin (%)	**42.95%**
NERC Reference Margin Level (%)	**13.75%**

Assessment Area Capacity Mix



Planning Reserve Margins

The Anticipated Reserve Margin is projected to be 42.95 percent for the 2012/2013 winter season. This estimate is above the minimum 13.75 percent Target Reserve Margin level for ERCOT. The ERCOT minimum Target Reserve Margin, referred to as the Planning Reserve Margin in ERCOT's documentation, of 13.75 percent is based on Loss-of-Load Events (LOLEv) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in2010.[40]

Use of an extreme temperature assumption (90/10 scenario) to produce a revised load forecast produces a peak demand forecast for the 2012/2013 winter season of 58,138 MW. The 90/10 forecast is 10 percent higher than the average (50/50) weather profile which results in an Existing Certain Reserve Margin of 26.5 percent.

A 925 MW thermal generation plant that was scheduled to be available for the summer of 2012 was delayed and is not expected to be available until March 2013. Even without this unit, the ERCOT Region is expected to have adequate resources for the 2012/2013 winter.

Demand

Several areas in the ERCOT Region have and are experiencing significant load growth due to increased petroleum extraction activities. ERCOT is working with affected transmission owners to develop transmission improvements to serve these increased loads reliably. Although the load growth is significant at specific stations, the aggregate load growth from these activities is not expected to have a significant impact on system-wide resource adequacy.

According to the ERCOT demand forecast, Total Internal Demand is forecasted to be 52,909 MW based on average winter weather conditions. This is a decrease from the forecasted peak of 53,562 MW for the winter season of 2011 – 2012, but an increase from the actual 2011/2012 winter system peak of 50,969 MW. The growth rate from last winter's actual peak load (50,969 MW) to this winter's forecasted peak load (52,909 MW) is 3.8 percent. The growth rate from last winter's forecasted peak load (53,562 MW) to this winter's forecasted peak load (52,909 MW) is a negative rate of 1.2 percent.

Demand-Side Management

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

ERCOT expects an incremental 119 MW of energy efficiency improvements across the ERCOT Region for the 2012/2013 winter season. This incremental energy efficiency is the result of recent energy efficiency improvements installed by transmission owners as a result of legislative requirements.

Load Resources (LR)[41] providing Responsive Reserve Service[42] are anticipated to provide an average of approximately 946 MW of dispatchable, contractually committed Demand-Side Load as a Capacity Resource for the 2012/2013 winter season. This set of loads is the only demand-side resource providing ancillary services to the ERCOT grid.

ERCOT's Emergency Response Service (ERS), which is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "Firm" load, represents Demand-Side Contractually Interruptible (Curtailable) Demand. ERCOT has procured 502 MW of ERS Load for the ERS contract period of October 2012 to January 2013.

Together these two programs (LR and ERS) would reduce winter peak demand by approximately 2.8 percent if activated. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[43]

Generation

Existing-Certain generation capacity in ERCOT, as reported by generation owners, for the 2012/2013 winter season is expected to be 73,282 MW.

A total of 1,357 MW of wind generation capacity (118 MW effective on peak due to the Effective Load Carrying Capability (ELCC) of wind resources) is expected to be added during the 2012/2013 winter season. Also, 36 MW of battery storage resources are expected to be added during the 2012/2013 winter season.

There are no units classified as Existing-Other in ERCOT, while there are 3,756 MW of Inoperable Resources (mothballed capacity) in ERCOT for the 2012/2013 winter season. This is an increase of 1,810 MW from the 1,946 MW of mothballed capacity noted during the ERCOT 2012 Summer Assessment. The Inoperable Resources consist of units that are classified as mothballed by their owners and are not expected to be available during the 2012/2013 winter season. This capacity is not counted toward reserves during the 2012/2013 winter season. No additional unit retirements, project deferments, derates or other capacity reductions are expected prior to or during the 2012/2013 winter season.

No significant change is expected in the availability of "behind-the-meter" generation for the 2012/2013 winter season. There is 3,168 MW of "switchable" generation that can operate in the ERCOT system or in adjacent (not synchronously interconnected) regions. ERCOT counts all of this generation capacity as available, except for 317 MW, which is obligated to serve load outside of the ERCOT Region.

Capacity Transactions

The ERCOT Region is a separate Interconnection with only asynchronous ties to Southwest Power Pool (SPP) and Mexico's Comision Federal de Electricidad (CFE). As such, ERCOT 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 block transfer of discrete loads. For the 2012/2013 winter, 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

[41] See Section 3.17 and 3.18 of http://www.ercot.com/content/mktrules/nprotocols/current/03-030112_Nodal.doc; Previously referred to as Load Acting as Resources (LaaRs).
[42] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.
[43] http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc

transfer capability and are included to reflect emergency support arrangements. Several SPP members own 317 MW of a power plant located in the ERCOT Region, resulting in a Firm export of that amount from ERCOT to SPP.

Transmission

Several significant transmission improvements are expected to be completed before February 2013 in the ERCOT Region. These are expected to meet reliability needs or reduce market congestion prior to or during the 2012/2013 winter season.[44]

Operations

There are no significant or unusual operating conditions that could significantly affect system operations for the 2012/2013 winter.

Vulnerability Assessment

Currently available information indicates that it is unlikely that water availability will limit generation resources during the 2012/2013 winter season.

In the ERCOT Region, generator owners and operators are responsible for their own fuel supply and transportation arrangements. In addition, ERCOT is a member of the Texas Energy Reliability Council; this group coordinates between the gas and electric industries and, if necessary, allocates deliveries of natural gas during periods of high demand. In the event of forecasted extreme weather and possible fuel curtailments, ERCOT may request fuel capability information from generation entities to prepare operationally for potential curtailments.

ERCOT has recently received a contractor's analysis of potential impacts of gas transportation limitations on grid reliability. This study found that any such impacts are unlikely and expected to be minor.[45] Additionally, coal transportation issues are not expected to have a reliability impact on the ERCOT Region during the upcoming winter season.

As a result of the recent ruling by the D.C. Court of Appeals vacating the Cross-State Air Pollution Rule, it is not expected that environmental regulations will have an impact on availability of generation resources during the upcoming 2012/2013 winter season. There are no unit outages for installation of retrofit equipment expected to occur during the upcoming 2012/2013 winter.

[44] Additional details on transmission projects can be found in the "Report on Existing and Potential Electric System Constraints and Needs" located on the following website: http://www.ercot.com/content/news/presentations/2012/2011 percent20Constraints percent20and percent20Needs percent20Report.pdf

[45] http://www.ercot.com/content/meetings/board/keydocs/2012/0221/Item_06_-_Gas_Risk_Study.zip

FRCC

2012/2013 Winter Season: Assessment Area Summary

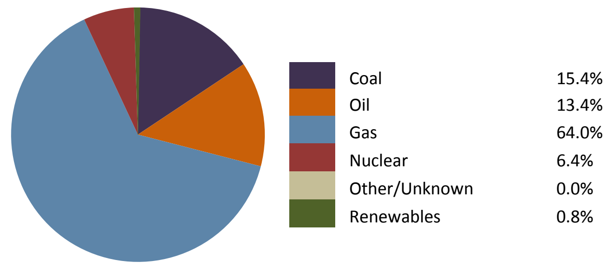
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**46,864**
Load-Modifying Demand Response	3,306
Net Internal Demand	**43,558**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	47,613
Actual Demand	39,924

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	2,212
Existing-Certain and Future-Planned Capacity	55,393
Anticipated Resources	**57,605**
Anticipated Reserve Margin (%)	**32.25%**
Existing-Other and Future-Other Capacity	1,071
Prospective Resources	**58,675**
Prospective Reserve Margin (%)	**34.71%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

The FRCC is projecting adequate Reserve Margins during the upcoming 2012/2013 winter. A 15 percent Reserve Margin criteria is required by the Florida Public Service Commission for the FRCC Region for all planning horizons. Based on the expected load and generation capacity, the calculated Anticipated Reserve Margin for the winter of 2012/2013 is 32.2 percent when Load Management and Interruptible loads are treated as a demand reduction.

Factors impacting the winter Reserve Margin include a 3 to 4 year period of weak economic demand resulting in more than adequate Reserve Margins. The weakness in the housing market, namely the tight credit levels, the drop in housing values below the outstanding mortgage levels, and lack of employment growth, all have hampered the overall mobility of residences to relocate to other areas. A rebound in the economy could potentially increase the demand, energy, and load projections that could result in realignment with previous projections.

Demand

Last year's peak demand forecast for the winter of 2011/2012 was 47,613 MW, which was 7,689 MW (19.3 percent) above the 2011/2012 actual demand of 39,924 MW. The FRCC Assessment Area is forecasted to reach its 2012/2013 winter non-coincident peak total internal demand of 46,864 MW in January 2013 representing a projected demand increase of 17.4 percent above the unusually mild winter demand experienced during January of the 2011/2012 winter season. This projection for the 2012/2013 winter peak demand is consistent with historical weather-normalized FRCC demand growth yet it is 1.6 percent lower than last year's winter forecast of 47,613 MW.

The small decrease in the 2012/2013 projected winter peak demand is attributed to lower expected consumption and economic activity compared to assumptions used in the previous projection. Load growth across individual Load Serving Entities (LSE) in the Region is proportional with the level of load growth seen across the FRCC Assessment Area.

Demand-Side Management

The projected 2012/2013 winter peak Total Internal Demand includes 3,306 MW of potential demand reductions from the use of load management (2,727 MW) and interruptible demand (579 MW).

Generation

The FRCC Region counts on 56,193 MW of Existing - Certain resources, of which 44 MW are hydro and 339 MW are Biomass. Potential solar capacity is projected to be 49.3 MW; however, most of this capacity is de-rated with approximately

1.7 MW considered as a Firm resource available during peak demand, with the remainder being used as an energy-only resource. Derated hydro capacity will be 11 MW. There are 2,033 MW of Existing-Other member-owned capacity presently placed into Inactive Reserves, while Existing-Other merchant plant capability of 193.2 MW is potentially available as future resources for FRCC members and others.

Approximately 60 percent of the Region's annual energy consumption and seasonal demand requirements are supplied by generation whose primary fuel source is natural gas. Nearly half of the generation fueled by natural gas has dual fuel capability therefore reducing the risk of these resources not being available due to unexpected fuel supply issues.

There are no retirements planned for during the upcoming winter season, however, 765 MW of generation are scheduled to be placed into Inactive Reserves[46] near the start of the winter season having functioned earlier in the year as replacement capacity for unit upgrades that have been completed. These activities are not expected to have an impact on ensuring that adequate generation will be available to serve load.

There are 865 MW of capacity not included in the winter forecast due to a long-term outage. This capacity is scheduled to be returned to service in late 2014. Another 822 MW of capacity is on short-term outage during the upcoming winter months, and will not be placed back into service until after the winter season.

Capacity Transactions

There are 1,340 MW of generation under Firm contract, available to be imported into the Region from the SERC-SE Assessment Area throughout the winter season, and another 872 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area. These purchases have Firm transmission service to ensure deliverability into the FRCC Region.

The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between entities within the SERC-SE Assessment Area and FRCC entities.

Transmission

Currently the FRCC Region expects to have multiple Bulk Electric System (BES) facilities out of service during the 2012/2013 winter season. The current planned outages are staggered as to limit the impact and exposure to the BES during the winter season. These respective outages were studied as part of the FRCC's Operational Seasonal Study. As a result, coordinated corrective action plans were developed to ensure reliability during the 2012/2013 winter season.

FRCC Region has not identified any specific large-scale projects that are needed to maintain or enhance reliability during the 2012/2013 winter season. The FRCC's Operational Seasonal Study did identify limiting elements associated with BES facilities that will be replaced prior to the 2012/2013 winter peak. Additions to the BES within the FRCC Region are primarily related to system expansion in order to serve forecasted demands and maintain the reliability of the BES.

Operations

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the 2012-2012 winter peak demand. The FRCC performed a Winter Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the BES within the FRCC Region under expected 2012/2013 winter peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria could be successfully mitigated under normal conditions, single contingency events, and selected multiple contingency events. Based on the FRCC Winter Transmission Assessment and

[46] IEEE 762: Inactive Reserves – "the state in which a unit is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time." FRCC does include Inactive Reserves capacity in the calculation of Reserve Margins when this generation is not in commercial service.

Operational Seasonal Study, no unusual operating conditions are expected to impact reliability for the upcoming 2012/2013 winter.

Vulnerability Assessment

Two 800MW class units are scheduled to be unavailable during a defined period within the study horizon. Based on the FRCC Winter Transmission Assessment and Operational Seasonal Study, the unavailability of these units is not anticipated to cause any reliability concerns.

The FRCC Region does not anticipate any impacts to the seasonal plan or in operations resulting from any potential capacity reductions stemming from forthcoming environmental and/or regulatory requirements. In addition, existing operating procedures can adequately address the integration of limited amounts of variable resources for the 2012/2013 winter.

For the 2012/2013 winter season, no concerns are anticipated due to a limited fuel supply within the FRCC Region. There are no fuel availability or supply issues identified at this time. Based on recent studies, current fuel diversity, alternate fuel capability and fuel study results, the FRCC does not anticipate any fuel issues affecting resource capability during the 2012/2013 winter season.

MISO

2012/2013 Winter Season: Assessment Area Summary

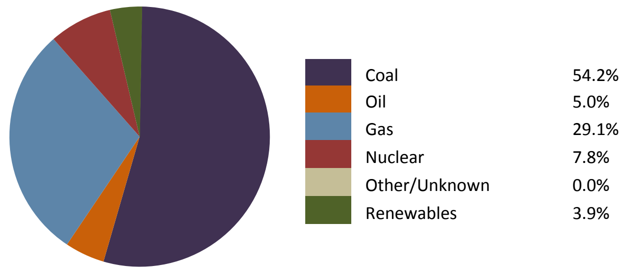
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**75,085**
Load-Modifying Demand Response	2,898
Net Internal Demand	**72,187**

Assessment Area Footprint

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	79,994
Actual Demand	72,739

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	3,001
Net Capacity Transactions (Firm and Expected)	2,714
Existing-Certain and Future-Planned Capacity	103,826
Anticipated Resources	**109,541**
Anticipated Reserve Margin (%)	**51.75%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**109,541**
Prospective Reserve Margin (%)	**67.89%**
NERC Reference Margin Level (%)	**15.40%**

Assessment Area Capacity Mix



Assessment Area Highlights

Currently, MISO's membership consists of 40 Transmission Owners with $17.8 billion in transmission assets under MISO's functional control and 98 Non-transmission owners. MISO has four Balancing Authorities in the region, including the MISO Balancing Authority, and experiences its annual peak during the summer season. MISO's scope of operations encompasses 49,641 miles of transmission over 13 states and one Canadian province. MISO's Energy and Operating Reserves market includes 363 market participants serving over 38.9 million people.

MISO continues to establish reserve margin requirements for its members. For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent. The PRMSYSIGEN for the MISO Assessment Area is based on Net Internal Demand and Anticipated Capacity Resources. The anticipated Reserve Margin and Prospective Reserve Margin for the winter are 51.7 percent and 67.9 percent, respectively. These reserve margins are based on an additional 129 MW of capacity added during the 2012/2013 winter.

The forecasted Total internal peak demand for the 2012/2013 winter is 75,084 MW. Last year's forecasted peak Total Internal Demand for the 2011/2012 winter assessment period was 80,572 MW. This decrease (about 7percent percent) is due to the transfer of Duke Energy Ohio and Kentucky to PJM on Jan 1, 2012. MISO does not anticipate any significant transmission issues to impact reliability during the 2012/2013 winter.

Planning Reserve Margin

For the winter of 2012/2013 the existing certain reserve margin is 51.7 percent which exceeds MISO's Planning Reserve Margin Requirement (PRMR)[47] of 16.7 percent. The anticipated reserve margin is 57.1 percent exceeding the PRMR, and the prospective planning reserve margin of 73.9 percent exceeds the PRMR. MISO is projecting adequate Planning Reserve Margins for the 2012/2013 winter.

Demand

During last year's winter season, MISO experienced an instantaneous peak of 74,011MW on December 6th hour ending 19 EST. The instantaneous load is the highest value metered during the peak hour. The 2011/2012 winter peak demand was

[47] For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent. For more information regarding how MISO establishes requirements please see the 2012 LOLE Study Report.

forecasted to be 75,363 MW. Last year's demand forecast of 75,363 MW is 0.4 percent higher than this year's demand forecast of 75,084 MW.

Demand-Side Management

MISO bases its resource evaluation on the actual market peak. MISO currently separates Demand Response Resources into two categories, Interruptible Load and Direct Control Load Management (DCLM). Interruptible load of 2,593 MW 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. DCLM of 305 MW 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.

Generation

The total amount of current generation for winter 2012/2013 is 126,526 MW where the Existing-Certain generation is 103,825 MW, the Existing-Other is 11,652 MW, and the Existing-Inoperable is 1,625 MW

Last year's Existing (Certain, Other, and Inoperable) capacity of 128,519 MW is 1.6 percent higher than MISO's projected Existing capacity of 126,526 MW for the upcoming winter season. This difference is mostly due to exit of Duke Ohio and Kentucky from MISO into PJM effective January 2012. The remaining MW changes were from new generation,[48] retirements and suspensions,[49] and reclassified units.[50]

The three primary fuel sources for MISO are coal, gas and nuclear. Coal units will account for 54.2 percent (62,003 MW), while gas and nuclear units will be 28.5 percent (32,690 MW), and 7.1 percent (8,203 MW), respectively.

MISO has not identified areas of concern regarding the reliability of its fuel sources; however, MISO is currently in the process of identifying areas of concern regarding the reliability of natural gas. In 2012, approximately 33 percent of MISO's gas-fired power plants are dual-fuel capable with ability to switch within zero to six hours. Approximately 20 percent of the total natural gas fleet, MISO has Firm gas supply contracts.

There are 129 MW of Future-Planned resources projected to come online throughout the assessment period. These units (natural gas and wind) are expected to be on line by January 2013.

Between May 2012 and October 2012, MISO has experienced 382 MW of unit retirements. 80 percent of the units retired in June of 2012, while the remaining units are scheduled to retire in October of 2012. During 2012/2013 winter seasons, 314 MW of unit retirements are projected by MISO. The majority will take place in December 2012.

Currently, 10,722 MW of wind resources are registered with MISO; however, MISO applies a 14.7 percent wind capacity credit to MISO wind resources based on their historical performance. The 14.7 percent system wide MISO wind capacity credit is based on determining the Effective Load Carrying Capacity (ELCC) of the intermittent wind resources.[51] Applying the 14.7 percent capacity credit brings the wind capacity down from 10,722 MW to 1,576 MW; however, MISO is not expecting 1,576 MW on peak. Of the 1,576 MW of wind, only 563 MW are registered as designated network resources in March 2012 commercial model, and are expected to serve MISO load during the 2012 winter season. Therefore, of the 10,722 MW of registered wind resources, MISO anticipates 563 MW of wind capacity on peak during the 2012 winter.

Capacity Transactions on Peak

The MISO only reports net power imports to the MISO market or reported interchange transactions into the MISO market. The forecast reflects 2,714 MW of power imports from year-to-year. All these imports are Firm and fully backed by Firm transmission and Firm generation.

[48] New Generation does not necessarily refer to newly built generation. It is simply new from the March 2011 Commercial Model to the March 2012 Commercial Model.
[49] Retirement and suspension information gathered per the Attachment Y process.
[50] MW Change from last year Commercial Model, Unit either designated to BTMG or Psuedo Tied Out of MISO
[51] For more detailed information regarding the wind capacity credit and ELCC study please see the 2012 LOLE study report.

Transmission

At this time MISO does not anticipate any project delays or temporary service outages during the upcoming winter season. There are no concerns in meeting target in-service dates of transmission identified. MISO does not have any transmission constraints that could significantly impact reliability.

Two main projects with in-service date of December 2012 that enhance the reliability of the system during 2012/2013 winter are the breaker replacement project throughout the ITC 345KV and 120 KV system, and addition of a 230/115 kV transformer at Cass Lake station.

Operational Issues

MISO is not anticipating any unusual operating conditions during the 2012/2013 winter.

Vulnerability Issues

New and proposed regulatory compliance obligations will potentially cause the retirement of an estimated 12 GW of coal-fired capacity in MISO, causing a shift in the region’s fuel mix. Natural gas-fired plants are expected to replace much of the retired capacity.

Additional Information

MISO’s membership has changed since the 2011 winter. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1st 2012, removing approximately 5,700MW of load and generation from MISO’s footprint. The Entergy operating companies Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. intend to join MISO in December 2013. Total Internal Demand and Net Energy Load for Entergy are not included in the above sections as the current Module E Capacity Tracking tool doesn’t capture the information. MISO is not including Entergy in the 2012/2013 winter analysis.

MRO-Manitoba Hydro

2012/2013 Winter Season: Assessment Area Summary

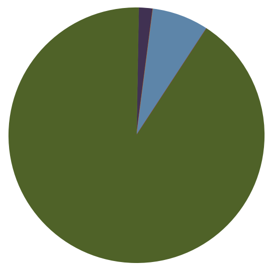
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**4,407**
Load-Modifying Demand Response	225
Net Internal Demand	**4,182**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	4,477
Actual Demand	4,371

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-50
Existing-Certain and Future-Planned Capacity	5,464
Anticipated Resources	**5,414**
Anticipated Reserve Margin (%)	**29.46%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**5,414**
Prospective Reserve Margin (%)	**29.46%**
NERC Reference Margin Level (%)	**12.00%**

Assessment Area Capacity Mix



Coal	1.8%
Oil	0.0%
Gas	7.2%
Nuclear	0.0%
Other/Unknown	0.0%
Renewables	91.1%

Assessment Area Highlights

The purpose of this section is to present winter 2012 - 2013 projections for reliability, resources, demand, and transmission infrastructure in the Manitoba Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The Reserve Margins for the Manitoba Assessment Area are based on Anticipated or Prospective resources. The Planning Reserve Margins, 29.5 percent, (Existing-Certain and Net Firm Transactions; Anticipated; Prospective) will remain above Manitoba Hydro's Reference Reserve Margin Level of 12 percent during the 2012 - 2013 winter assessment period.

An additional 200 MW of new hydro capacity will be in-service for the 2012 - 2013 winter season. The Total Internal Peak Demand in Manitoba for the 2012/2013 winter season is forecast to be 4,407 MW in January 2013. Total Internal Demand for the winter peak has decreased from 4,477 MW for the 2011/2012 winter season. The small difference is a result of updating input variables into the Peak Load Model,[52] namely updating weather and economic variables.

Planning Reserve Margins

Manitoba is projecting above adequate Planning Reserve Margins during the 2012/2013 winter season for the existing, anticipated, and prospective reserve margin cases. All reserve margin cases for all winter months are projected to exceed 29 percent.

Manitoba Hydro has planned and maintained its system in accordance with good utility practice such that adequate Planning Reserve Margins shall be maintained throughout the winter season. No unit retirements, extraordinary load growth or additional environmental restrictions are expected. Manitoba Hydro does not anticipate any significant challenges to maintaining the Planning Reserve Margin projections throughout the winter season.

Demand

Last winter's actual peak demand of 4,371 MWs occurred in January 2012 compared to the forecasted peak of 4,477 MW. December 2011 through February 2012 was warmer than normal and the peak demand occurred at warmer temperatures than previous years.

[52] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/attachment_1.pdf.

This year's Total Internal Demand forecast of 4,407 MW is 1.6 percent lower than last year's Total Internal Demand forecast. The small difference is a result of updating input variables into the Peak Load Model, namely updating weather and economic variables. Economic forecast assumptions come from the 2012 Economic Outlook[53] and the 2012 Energy Price Outlook[54] prepared by Manitoba Hydro's Economic Analysis Department.

Demand-Side Management

Manitoba Hydro is projecting 19 MW of energy efficiency (conservation) to be realized for the 2012/2013 winter peak. There is 225 MW of demand response projected to be available for the 2012/2013 winter peak. Manitoba Hydro deploys Demand Response programs only during system contingencies/emergencies. Interruptible customer load may only be used to reduce peak demand if contingency reserve obligations are in jeopardy of not being met. The Demand Response program used for Ancillary Services (Non Spinning Reserves) in place at Manitoba Hydro is the Curtailable Customer Load Option R[55]. Manitoba Hydro has an agreement with a large industrial customer to carry 50 MW of Non Spinning Reserves in the form of a curtailable customer load.

Generation

5,464 MW of Existing-Certain resources are expected to be available for the winter 2012/2013 peak. Hydro is the primary fuel source in Manitoba. Reservoir levels are sufficient to meet both peak demand and daily energy demand. Manitoba Hydro is not anticipating any issues that could significantly impact reliability of hydro as a fuel source.

For resource adequacy analysis, Manitoba Hydro uses 8 percent of wind generation nameplate for summer capacity and 0 percent of wind generation nameplate for winter capacity. Short-term impacts for changes to capacity include the Wuskwatim Generating Station which is expected to be in-service for the winter season, adding 200 MW of Existing-Certain capacity to Manitoba's generation. Unit outages for the winter season are expected to amount to approximately 179 MW during the winter peak. Potentially 25 MW of capacity will be returned to service after prolonged maintenance. There are no significant short-term impacts expected with this additional capacity which will either marginally supplement Manitoba's real-time exports or suppress real-time imports. Approximately 74 MW of capacity is expected to be unavailable during the winter season due to long-term outages, no significant short-term impacts are expected due to this lost capacity as Manitoba's internal generation plus import capability far exceeds their expected internal demand over the upcoming winter peak load.

Wind resources in Manitoba Hydro include two existing variable capacity resources, St. Leon wind farm, and St. Joseph wind farm, which have about 120.5 MW and 138 MW of nameplate capacity (maximum capacity), respectively. Although Manitoba Hydro has contractual rights to all capacity from these facilities no capacity credit is given to wind resources for winter reliability/capacity purposes.

The expected on-peak capacity for hydro is 5,173 MW for the winter peak. Expected on-peak values for hydro generation are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines.[56] The expected on-peak capacity that a unit can sustain is computed using the test results.[57]

Capacity Transactions

All of Manitoba Hydro's dependable exports and/or imports are backed by contracts and Firm transmission service. Manitoba Hydro has 550 MW of on-peak capacity exports and 500 MW of on-peak capacity imports in the winter season. Manitoba Hydro's emergency energy imports are characterized under the MISO-Manitoba Hydro Contingency Reserve

[53] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_4_1.pdf
[54] The Energy Price Outlook is proprietary and not available for public consumption.
[55] Page 4 of http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_10_4.pdf
[56] www.midwestreliability.org/03_reliability/06_gtrtf/Documents/MRO_Generator_Testing_Guidelines.pdf
[57] These values are adjusted for ambient conditions and don't include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculations is the average net integrated hourly capability for all hours of historical operation for each month.

Sharing Group (CRSG) agreement. Only upon significant contingencies involving the loss of generation or transmission facilities do Manitoba Hydro system operators have the ability to request emergency energy imports from MISO under the CRSG. The total reserve carried in the reserve sharing group is 2,000 MW (150 MW for Manitoba Hydro, 1850 MW for MISO). There is no new additional import/export capability planned for the 2012/2013 winter season.

Transmission

Manitoba Hydro does not foresee any significant project delays or temporary service outages of any significant transmission facilities that could impact reliability.

Operations

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

Manitoba Hydro does not anticipate any unusual operating conditions that could significantly impact reliability for the upcoming winter season.

Vulnerability Assessment

As a predominately hydro region, Manitoba Hydro has an energy criterion which requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions on the 97 year hydraulic flow record are repeated. In other words, the Manitoba Hydro system is designed and operated to serve all Firm load requirements under the worst inflow conditions on record coincident with high winter load conditions. Drought contingency plans are well established and operational concerns are not a factor.

Manitoba Hydro's system tends to be energy constrained rather than capacity constrained. As a result of the tendency to be energy constrained, there are typically significant amounts of surplus generation capacity available. Therefore it is possible to manage resources around significant long-term generator outages of capacity resources.

The most significant operational concern for this scenario is the need to carry contingency reserves elsewhere when the non-spinning reserves normally available as Demand Response are unresponsive. In addition, when interruptible customer load is unavailable, system operators will have to rely more heavily on emergency energy purchases prior to shedding Firm load under severe system contingencies.

The Raven Lake MR11 Tripping SPS was installed at Raven Lake station in October 2011 with the SPS tripping function disabled and will be in service for the 2012/2013 winter season. The purpose of this SPS is to prevent overloading of the 115 kV line MR11 under certain system contingencies.

Manitoba Hydro does not anticipate any supply or transportation issues for the 2012/2013 winter season. On-site coal supplies are adequate with contracts in place for additional deliveries if required. Alberta natural gas supplies and transportation to Manitoba are plentiful. TransCanada Pipeline has been experiencing significant de-contracting of Firm transport by its customers resulting in additional transport available should Manitoba Hydro need 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.

MRO-MAPP

2012/2013 Winter Season: Assessment Area Summary

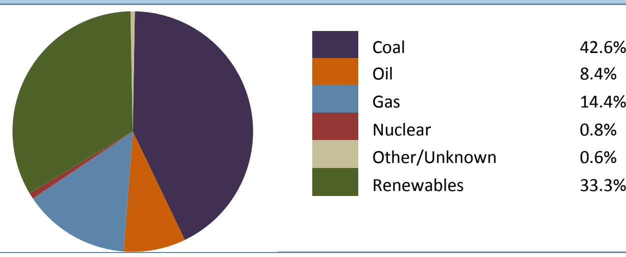
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**5,512**
Load-Modifying Demand Response	375
Net Internal Demand	**5,137**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	5,036
Actual Demand	4,371

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-507
Existing-Certain and Future-Planned Capacity	7,408
Anticipated Resources	**6,901**
Anticipated Reserve Margin (%)	**34.36%**
Existing-Other and Future-Other Capacity	233
Prospective Resources	**7,134**
Prospective Reserve Margin (%)	**38.89%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

MAPP is projecting adequate Planning Reserve Margins during the 2012/2013 winter assessment period. All categories of reserve margin (Existing 33 percent, Anticipated 34 percent, and Prospective 39 percent) exceed the NERC target reference margin of 15 percent for thermal systems and 10 percent for hydro systems. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for the upcoming winter season.

Demand

The 2011/2012 MAPP actual winter peak non-coincident demand was 5,217 MW compared to the demand forecast of 5,078 MW in the 2011/2012 MAPP winter reliability assessment which was about 2.7 percent under actual winter peak non- coincident demand. This winter's peak demand forecast is 5,561 MW which is about a 7 percent increase over last winter's actual peak. The MAPP non-coincident internal peak demand forecast was developed by aggregating individual entity peak demands.

Each MAPP LSE uses its own forecasting methodology. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal or 50/50 weather patterns. There were no changes in this year's forecast assumptions in comparison to last year.

Load growth in the MAPP assessment area can be attributed to increasing energy needs of Minnkota Power Cooperative (MPC) end use customers and the addition of new customers in MPC. Additionally Basin Electric Power Cooperative (BEPC) is continuing to experience load growth in western North Dakota due to increased oil activity in excess of normal load growth.

Demand-Side Management

The total amount of Energy Efficiency (Conservation) that is expected to be available on-peak for the 2012/2013 winter season is 29 MW. The total amount of Demand Response that is expected to be available on-peak for the 2012/2013 winter season is 375 MW. The bulk of the demand response in the MAPP Assessment area is located in MPC's service territory and is treated as load-modifying.

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 assessment period. MAPP entities utilize various measurement and verification programs for demand response, such as those based upon International Performance Measurement and Verification

Protocols (IPMVP).[58] Energy efficiency is verified through several means, such as use of the Minnesota Deemed Savings Database[59] provided by the Minnesota Office of Energy Security.[60]

Generation

The Existing-Certain capacity resources at the time of the assessment period are 7,340 MW. There are 233 MW of Existing-Other and 0 MW of Existing-Inoperable capacity. The primary fuel sources in MAPP are coal (45 percent), hydro (31 percent), natural gas (10 percent), oil (9 percent), and wind (4 percent). MAPP does not have concerns about the reliability of its most dominant fuel sources.

There are 68 MW of Future-Planned resources projected to come online throughout the assessment period. Northwestern Energy is in the process of installing an internal peaking unit of 60 MW in Aberdeen, South Dakota. The unit will be simple cycle gas fired and is expected to be on line by January 2013. Hutchinson Utilities Commission is adding 8 MW of natural gas fired generation.

There have been no significant unit retirements, deferments, derates, or other negative impacts to Existing-Certain capacity in the prior year. Further, there are no significant unit retirements, deferments, derates, or other negative impacts projected to Existing-Certain capacity during the assessment period.

MAPP is not projecting any significant new generation, generator uprates, units taken out of service, units brought back in service, or long-term outages over the assessment period. There has been no change in behind-the-meter generation, or changes in other “non-traditional” resources in the previous year.

Of the Existing-Certain capacity resources, 436 MW of wind generation is expected on-peak, with a nameplate rating of 1,080 MW. To determine wind expected peak, MAPP utilizes a methodology that is based on a median of actual wind output.[61] Additionally, there are 1,980 MW of hydro and 3 MW of biomass Existing-Certain capacity resources in MAPP.

Capacity Transactions

MAPP is projecting total Firm imports of 262 MW. MAPP is projecting total Firm exports of 768 MW. For both imports and exports, Firm contracts exist for both the generation and the transmission service. Firm contracts are at least one year in length, and some extend out twenty years or more. Capacity transactions projected beyond the length of Firm contracts may be based on extensions of those contracts. Transmission providers within MAPP handle Liquidated Damage Contracts (LDC) according to their tariff policies.[62] MAPP is forecasted to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

No emergency imports are required to meet the Reserve Margin target in MAPP. There are no additional import/export capabilities newly available for the 2012/2013 winter season.

Transmission

MAPP has not identified any project delays or temporary service outages of any significant transmission facilities during the 2012/2013 winter season.

The Basin Electric Power Cooperative/Western Area Power Administration/Heartland Consumer Power District Integrated System has energized several new interconnections since the 2012 summer season. A new Wheelock 230/115 kV substation is scheduled to be energized late 2012 on the Williston – Tioga 230 kV line to support load growth in the region. New Southwest Minot and Berthold substations are also scheduled to be added to the Logan – Kenmare – Tioga 115 kV line by

[58] Efficiency Valuation Organization - http://www.evo-world.org/
[59] MN Department of Commerce - http://mn.gov/commerce/energy/topics/conservation/Design-Resources/Deemed-Savings.jsp
[60] MPC staff provides direction and expertise to its member cooperatives for both conservation and energy efficiency improvements. MPC has been and remains active in its load management program involving its member cooperatives.
[61] These values are adjusted for ambient conditions and don't include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculations is the average net integrated hourly capability for all hours of historical operation for each month.
[62] Most MAPP LSEs are within non-retail access jurisdictions and therefore liquidated damages products are not typically used.

the end of 2012. Northwestern Energy is reconductoring the 115 kV line between the Seibrecht Substation and the Redfield Jct. Substation. The estimated completion of the first phase is November 2012. They are replacing 4/0 ACSR with 556 ACSR. The second phase of this project is to reconductor between Redfield Jct. and Huron "A" Tap and is scheduled to start in the spring of 2013.

Operations

No significant operational issues are expected this winter for the MAPP assessment area.

An extended drought could reduce the available cooling water at the Laramie River Station. Although there is the possibility of environmental restrictions affecting reliability in the near future, currently Heartland Consumer Power District (HCPD) believes that there are no regulatory/environmental restrictions that will affect system reliability this winter.

Vulnerability Assessment

A long-term drought in the region that results in significantly reduced hydroelectric production could cause a regional resource inadequacy. Similarly, an extended drought could reduce the available cooling water at the Laramie River Station.

MAPP does perform studies that consider known and anticipated fuel supply or delivery issues in its assessment. Because the MAPP Planning Authority area has a large diversity of 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 2012/2013 winter season. Any fuel supply issues that may develop will be handled on a case by case basis.

Adequate water is anticipated for normal generation during the winter assessment period. Coal stockpiles are near full and there does not appear to be any supply or transportation issues at this time.

Significant load growth is anticipated in the western North Dakota region due to oil production activity. Temporary operating guides will be developed for critical outages in the area to ensure reliable operation until transmission reinforcements are placed in service.

MRO-SaskPower

2012/2013 Winter Season: Assessment Area Summary

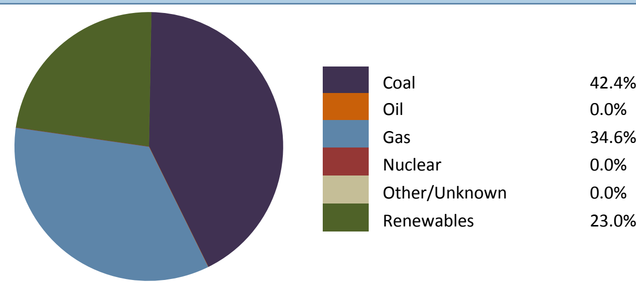
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**3,512**
Load-Modifying Demand Response	86
Net Internal Demand	**3,426**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	3,391
Actual Demand	3,241

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	3,901
Anticipated Resources	**3,901**
Anticipated Reserve Margin (%)	**13.86%**
Existing-Other and Future-Other Capacity	185
Prospective Resources	**4,086**
Prospective Reserve Margin (%)	**19.25%**
NERC Reference Margin Level (%)	**13.00%**

Assessment Area Capacity Mix



Assessment Area Highlights

Other than seasonal derates, there are no significant capacity changes since the release of the 2012 Summer Seasonal Reliability Assessment . According to the Saskatchewan demand forecast, Total Internal Demand is forecasted to be 3,500 MW for the 2012/2013 winter assessment period. Last year's forecasted peak Total Internal Demand for the 2011/2012 winter assessment period was 3,365 MW. This increase (about 4 percent) is due primarily to increased industrial activity in Saskatchewan. No significant transmission issues are expected to impact reliability during the 2012/2013 winter season.

Planning Reserve Margins

An adequate Planning Reserve Margin is projected for Saskatchewan during the 2012/2013 winter assessment period. Planning Reserve Margin's for all months this winter exceed 13 percent. Saskatchewan's criteria for adding new generation resources are based on Expected Unserved Energy (EUE). The probabilistic EUE value equates to an approximate 11 percent to 13 percent monthly Reference Margin Level. Adequate resources have been planned for Saskatchewan to meet anticipated load for the 2012/2013 winter assessment period.

There are no anticipated challenges that would lead to significant detractions of Planning Reserve Margin projections for Saskatchewan for the 2012/2013 winter season.

Demand

The 2011/2012 winter Total Internal Demand forecast was 3,365 MW. The actual 2011/2012 peak demand was 3,241 MW. The actual peak was lower than forecast due mainly to lower than expected industrial activity and a warmer than expected winter season. According to the Saskatchewan demand forecast, Total Internal Demand is forecasted to be 3,500 MW for the 2012/2013 winter assessment period. The 4 percent increase in the winter Total Internal Demand is due primarily to increased economic growth in Saskatchewan.

Demand-Side Management

Approximately 44 MW of energy efficiency and 86 MW of demand response are expected to be in use during the 2012/2013 winter peak. Demand response resources are treated as demand-side contractually interruptible.[63]

[63] Demand Response is used for reserve purposes in Saskatchewan.

The primary driver for Demand-Side Management (DSM) programs in Saskatchewan is economic incentive (difference in cost between providing the DSM program and the cost of serving the load). Increases in DSM for the 2012/2013 winter season will come from growth of existing programs. No new Demand Response programs are being incorporated for the 2012/2013 winter assessment period in Saskatchewan.

Generation

For Saskatchewan an average of 3,902 MW of existing-certain resources are expected to be available for the 2012/2013 winter assessment period. An average of 186 MW of existing-other resources includes wind derates; hydro derates, and scheduled maintenance.

The primary sources of fuel for Saskatchewan are coal, hydro, and natural gas. Saskatchewan does not anticipate any reliability issues associated with these fuel types. Natural gas resources have Firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts.

There are no Future-Planned resources, anticipated unit retirements, project deferments, or any other impacts that would affect the existing capacity level since the 2012 summer assessment period. Unit derates of less than 45 MWs for conventional units are expected. No generation additions or uprates are expected to occur during the 2012/2013 winter season. There are no additional units that will be taken out of service during the 2012/2013 winter season in Saskatchewan, other than those that are part of the regular maintenance plan. There are also no units that will be brought back into service during the 2012/2013 winter season in Saskatchewan, other than those that are part of the regular maintenance plan.

For Saskatchewan, an average of 39 MW of wind, 850 MW of hydro, and 10 MW of biomass is expected on-peak during the 2012/2013 winter season. Nameplate capacities of wind, hydro, and biomass are 197 MW, 853 MW, and 10 MW respectively. For the 2012/2013 winter season, Saskatchewan plans for 20 percent of wind nameplate capacity to be available to meet on-peak demand. This value was determined using historical data and analyzing the actual amount of wind available during the 4 hours of each daily peak over each month. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions.

On-Peak Capacity Transactions

At this time, there are no Firm imports and/or exports that are backed by contracts for the 2012/2013 winter season involving Saskatchewan. There will be no additions of import/export capabilities that will be newly available for the 2012/2013 winter season.

Transmission

There are no project delays or temporary transmission service outages for transmission facilities in Saskatchewan that are expected to impact reliability during the 2012/2013 winter season. Additionally, there are no specific new projects that have been identified to maintain or enhance reliability during the 2012/2013 winter season.

Operations

SaskPower performs daily assessments as to the adequacy of its generation fleet to meet the expected loads while maintaining its reserves. These assessments will take into account any extreme weather conditions and if warranted, refinements to those assessments will be completed as required.

Saskatchewan has no general operational concerns for the coming 2012/2013 winter season. No unit retirements, project deferments, derates, or other capacity reductions are expected in Saskatchewan for the 2012/2013 winter. When applicable, Saskatchewan plans to mitigate future capacity reductions with new sources of generation and/or Firm imports.

Vulnerability Assessment

Saskatchewan has no resource adequacy or operational concerns for the following conditions: long-term/ extended drought, significant long-term generator outages, unresponsive or unavailable demand response, or significant penetration of variable generation for the 2012/2013 winter season.

With regards to coordination with the fuel supply industry, coal resources have Firm contracts and are mine-to-mouth operations. Coal 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 47 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 on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts. Coordination meetings between the electric system and the natural gas transportation system are held to discuss operational and planning issues. These meetings enable both systems to be informed of any issues relating to security of supply for natural gas transportation.

NPCC Summary

The five Northeast Power Coordinating Council, Inc. (NPCC) Reliability Coordinator sub-areas, or subregions, are defined by the following footprints: (1) The Maritimes sub-Area (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd. and the Northern Maine Independent System Administrator, Inc); (2)New England (ISO New England Inc.); (3) New York (New York ISO); (4) Ontario (Independent Electricity System Operator); and (5) Québec (Hydro-Québec TransÉnergie).

The Planning Reserve Margins for the NPCC Assessment Area are based on Existing Certain and Net Firm Transactions resources. The Anticipated Planning Reserve Margin will remain above the Reference Reserve Margin Level during winter 2012/2013 season. According to the aggregate of NPCC demand forecasts, Total Internal Demand is expected to increase to 112,063 MW from the 2011/2012 winter amount of 111,804 MW. This equates to an annual growth rate of 0.2 percent.

Demand, Capacity & Planning Reserve Margins

A comparison of winter 2012/2013 projections, winter 2011/2012 forecasted and actual demands with the lowest planning reserve margin projections is as follows:

NPCC Sub-Area	2012/2013 Winter Forecasted Peak (MW)	2012/2013 Winter Forecasted Reserve Margin (percent)	2011/2012 Winter Forecasted Reserve Margin (percent)	2011/2012 Winter Forecasted Peak (MW)	2011/2012 Winter Actual Peak (MW)
Maritimes	5,246	30.2%	21%	5552	4,963
New England	22,355	65.3%	45%	22255	19,926*
New York	24,832	34.1%	47%	24533	23,901
Ontario	22,087	39.2%	36%	22311	21,847
Québec	37,543	10.9%	11%	37153	35,481

*Reconstituted peak was 21,354 MW.

The Maritimes, New England, Ontario and Quebec Subregions are projecting reserve margins that are higher than last winter. New York is projecting a lower reserve margin but it is still well in excess of any requirements.

The NPCC real time operating reserve requirements are indicated in the NPCC Directory #5, "Reserve." Existing-Certain resources expected in the NPCC Assessment Areas for the 2012/2013 winter months are shown below:

Month	Maritimes	New England	New York	Ontario	Québec
December 2012	6,560	34,010	31,877	28,984	39,754
January 2013	6,593	34,323	32,924	30,042	39,606
February 2013	6,599	33,104	32,418	29,058	39,428

Operations

The following are highlights that should be noted with regard to operations within NPCC during the winter 2012/2013 period:

- Two refurbished nuclear generators (1,500 MW) in Ontario are scheduled to return to service before 2012/2013 winter.
- The Beck-Packard 230 kV BP76 New York-Ontario tie is expected to return to service during the 2012/2013 Winter.
- The Point Lepreau nuclear station in the Maritimes is scheduled to return to service prior to the 2012/2013 winter period.
- The Gentilly-2 nuclear station in Québec will be retired for decommissioning at the end of 2012.
- Synchronous Condenser CS23 at Duvernay substation in the Montréal area, which has been out of service since June 2008 due to a transformer fault will be back in service for the 2012/2013 Winter Operating Period. This will enhance transmission capability on the Southern Interface in the load area of the system.
- Hydro-Québec TransÉnergie (HQT) is proposing to install a new generation rejection Type III SPS at Bersimis-1 and 2 Generating Stations. The SPS should be operational in October 2012. The SPS is required because a double-circuit 315-kV transmission line will be unavailable while work is being performed to integrate three wind power plants on the Bersimis sub-system

NPCC-Maritimes

2012/2013 Winter Season: Assessment Area Summary

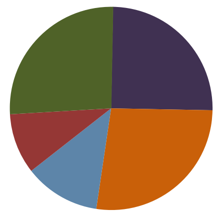
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**5,246**
Load-Modifying Demand Response	170
Net Internal Demand	**5,076**

Assessment Area Footprint

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	5,552
Actual Demand	4,963

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	14
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	6,593
Anticipated Resources	**6,607**
Anticipated Reserve Margin (%)	**13.86%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**6,607**
Prospective Reserve Margin (%)	**30.17%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

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 Area is projecting more than adequate surplus capacity margins above its operating reserve requirements for the winter 2012/2013 assessment period.

The projected reserve margins for the 2012/2013 winter period (for the months of December, January and February) range from 30.2 percent to 38.7 percent, with the minimum reserve margin of 30.2 percent projected for the month of January.[64] When compared to the corresponding projected reserve margins for the 2011/2012 winter period, the monthly reserve margins ranged from a minimum of 20.7 percent in the month of January to 25.7 percent.

Demand

The Maritimes Area 2011/2012 forecasted peak demand of 5,552 MW was projected to occur the week of January 8, 2012. The actual peak for the 2011/2012 winter was 4,963 MW and it occurred on February 13, 2012. The 2011/2012 actual winter peak was 589 MW (10.6 percent) lower than the forecasted peak demand. The difference can be attributed to the shutdown of a large industrial load and milder than expected winter temperatures. The Maritimes Area is forecasting a 5,246 MW peak demand for the 2012/2013 winter reporting period. The difference in the forecasted amounts is due to the loss of industrial load and warmer forecasted temperatures.

Demand-Side Management

In the Maritimes Area there is between 144 MW and 198 MW of interruptible demand available during the assessment period; there is 170 MW forecasted to be available at the time of the Maritimes Area seasonal peak. The interruptible load demand that is used comes from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

[64] The Reserve Margins for the Maritimes Assessment Area are based in accordance with NPCC Directory #1.

The Maritimes Area is broken up into sub-areas and each sub-area has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heat as the Maritimes Area is a winter peaking system.[65]

Generation

The Maritimes Area projected Total Internal Capacity is 7,423. The Maritimes Area only considers Existing-Certain resources when doing its seasonal assessment. There is a very diverse fuel supply made up of nuclear (Point Lepreau unit scheduled back in service October 2012), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood. The primary sources of fuel are hydro, oil, coal, natural gas and nuclear. Wind and biomass nameplate capacity make up only about 12 percent of the existing capacity. The Maritimes Area is a winter peaking system therefore units, which would affect system reliability, are not planned to be taken out of service during this period. During the 2012/2013 winter assessment period no anticipated capacity reductions expected to occur.

The Dalhousie coal fired plant, totaling 299 MW (a 96 MW unit and a 203 MW unit), retired on May 31, 2012. The Point Lepreau nuclear station is scheduled to be back in service October 2012. It has been off-line being refurbished since April 2008.

Wind capacity within the Maritimes Area is expected to be 816 MW with 168 MW expected on peak. Wind projected capacity is de-rated to its demonstrated average output for each summer or winter capability period. In New Brunswick, Prince Edward Island and NMISA, for wind facilities that have been in production over an extended period of time (three years), a de-rated monthly average is calculated using metering data from the previous three years of demonstrated performance over each seasonal assessment period. Nova Scotia has decided not to include any wind facilities towards their installed capacity (100 percent de-rated).

Maritimes Sub-Areas	2011/2012	2012/2013	
	Nameplate Capacity	Nameplate Capacity	On-Peak Capacity
New Brunswick	294	294	85
Prince Edward Island	164	164	71
Nova Scotia	274	316	0
NMISA	42	42	13
TOTALS	774	816	169

For those generators that have not been in service that length of time (three years), the derating of wind capacity in the Maritimes Area is based upon results from the September 21, 2005 NBSO report titled "Maritimes Wind Integration Study."[66] This wind study showed that the effective capacity from wind projects, and their contribution to LOLE was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area 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 Area resource adequacy assessment.

On-Peak Capacity Transactions

No on-peak capacity transactions have been scheduled at this time. The Maritimes, through existing agreements with neighboring Balancing Authority areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy. But the Maritimes Area does not rely on this assistance when doing its winter assessment.

Transmission

There are no project delays or anticipated transmission outages during the winter that would be expected to significantly affect reliability.

[65] For further information on the energy efficiency programs please review the following links: www.maritimeelectric.com , www.nppower.com , www.mainepublicservice.com , www.emec.com , www.nspower.ca/energy_efficiency/programs/

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

Operations

The Maritimes area does not anticipate any significant reliability concerns for the winter period.

The recent retirement of a 299 MW generating station on May 31, 2012 does not have a significant impact on capacity margins primarily because the Point Lepreau nuclear station is scheduled to return to service prior to the 2012/2013 winter assessment period.

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

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

Vulnerability Assessment

The Area is forecasting normal hydro conditions for the 2012/2013 winter assessment period. 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.

Load Management is not included in the resource adequacy assessment for the Maritimes Area. The interruptible load demand that is used is from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

The amount of wind generation presently operating does not require any special operational changes. If there were a significant increase of wind the New Brunswick System Operator as Reliability Coordinator for the Maritimes Area has the authority to curtail the variable generator as required.

The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian Federal and Provincial environmental regulations. For the 2012/2013 Winter Operating Period, there may be occasions when some units are required to be derated in order to meet these regulations. However, these occasions are expected to be infrequent, of short duration and are not included in the winter assessment.

It is the responsibility of the generator owners to ensure that fuel supplies are adequate. The Maritimes Area does not consider potential fuel-supply interruptions in the regional assessment. The fuel supply in the Maritimes Area is very diverse and it includes nuclear (scheduled back in-service October 2012), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood. As such the assessment area does not expect to experience any reliability issues resulting from fuel supply issues.

NPCC-New England

2012/2013 Winter Season: Assessment Area Summary

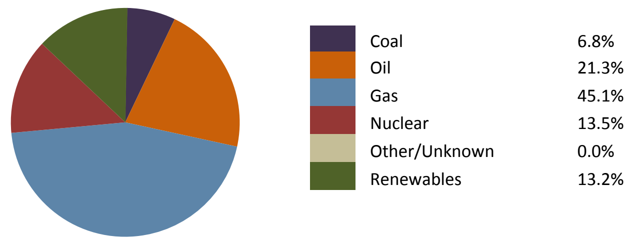
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**22,355**
Load-Modifying Demand Response	963
Net Internal Demand	**21,392**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	22,255
Actual Demand	19,926

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	957
Net Capacity Transactions (Firm and Expected)	475
Existing-Certain and Future-Planned Capacity	34,450
Anticipated Resources	**35,882**
Anticipated Reserve Margin (%)	**67.74%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**35,882**
Prospective Reserve Margin (%)	**67.74%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

ISO New England is projecting adequate Planning Reserve Margins during the 2012/2013 winter season. During the peak demand period in January the Planning Reserve Margin based on Existing-Certain capacity and Net Firm Transactions is 67.1 percent, and both the Anticipated and Prospective Reserve Margins are 67.7percent.

for the purposes of this report, the reference margin level is considered to be 15 percent, which is the target reserve margin assigned by NERC for predominantly thermal systems.[67]

ISO New England has adequate capacity consisting of Existing-Certain generation (34,323 MW), Future-Planned generation (127 MW), demand resources (1,920 MW) and net imports (475 MW) to meet the forecasted Total Internal Demand of 22,355 MW during the winter season. The lowest Anticipated Capacity Resources Reserve Margin of 13,400 MW (65.9 percent) occurs in the month of February.[68]

The amount of capacity that is procured annually through FCM is the amount required to serve the summer peak demand and operating reserves. Therefore, since New England is a summer peaking system with winter peaks historically about seventy five percent of the summer peaks, there will be enough capacity available to serve the lower winter peak loads and operating reserves.

ISO-NE projects available capacity for each week of the year within its Annual Maintenance Schedule (AMS).[69] The AMS's Operable Capacity Analysis takes into consideration the capacity purchased through the FCM, planned generator outages, potential for unplanned outages and generation at risk. "Generation at Risk due to Gas Supply" accounts apply for gas fired capacity expected to be at risk due to potential gas supply issues during cold weather conditions or pipeline maintenance outages. After taking into account the At-Risk generation due to Gas Supply, ISO-NE is still forecasting a sufficient winter capacity margin.

[67] New England does not have a fixed capacity or reserve margin requirement, rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. The capacity needs can vary from year to year depending on system conditions. Therefore,

[68] ISO New England ensures that it has enough electrical capacity to meet overall system needs through its Forward Capacity Market (FCM). The FCM purchases the amount of capacity required to satisfy the NPCC once in ten-year loss of load expectation resource planning reliability criterion through annual auctions three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions prior to the commencement year. These auctions are held to re-adjust installed capacity purchases and to ensure that adequate capacity will be purchased to meet system needs.

[69] The current copy of the Annual Maintenance Schedule is located on the ISO's web site at: http://www.iso-ne.com/genrtion_resrcs/ann_mnt_sched/index.html .

Demand

The 2011/2012 winter peak demand forecast was 22,255 MW. This was 901 MW (4.2 percent) higher than ISO-NE's reconstituted 2011/2012 winter actual peak demand of 21,354 MW, which occurred on January 4. The metered peak demand of 19,926 MW reflects reductions of 1,428 MW due to passive demand resources (energy efficiency). The primary reason for the lower than forecast peak demand was that the weather at the time of the actual peak was 23.7°F, while the 50/50 winter peak forecast is predicated on a temperature of 7.0°F.

The 2012/2013 winter peak demand forecast of 22,355 MW is 100 MW (0.4 percent) higher than the 2011/2012 winter peak demand forecast of 22,255 MW.

As noted by the minor change in the peak demand forecast between last winter and this upcoming winter, the key factors behind this low level of demand growth are the lingering effects of the economic recession.

Demand-Side Management

ISO-NE has 963 MW of passive demand resources that are forecast to be in-service during the 2012/2013 winter peak. Passive demand resources are non-dispatchable load reductions, typically consisting of energy efficiency measures or distributed generation that regularly operates to meet end use customer needs.[70] A total of 957 MW of active demand resources are expected to be available on peak. These demand resources are activated in real time during actual or anticipated capacity/operating reserve deficiencies.

Both passive and active demand resources are treated as capacity in ISO-NE's FCM. The 963 MW of passive demand resources CSOs are treated as demand reducers in this report resulting in a reduced Net Internal Demand. The 957 MW of active demand resources consist of Real-Time Demand Response and Real-Time Emergency Generation and are treated as dispatchable capacity, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 - Action During a Capacity Deficiency (OP 4).[71,72]

Generation

ISO-NE's Existing-Certain generating capacity during the month of January amounts to 34,323 MW based on Winter Seasonal Claimed Capability ratings. Natural gas-fired generation represents the largest component of ISO-NE's total installed capacity at 45.3 percent (15,599 MW), followed by oil-fired generation at 21.4percent (7,358 MW), nuclear generation at 13.6 percent (4,674 MW), and coal at 6.9 percent (2,367 MW). Hydroelectric capacity and pumped-storage capacity make up 4.7percent and 4.9 of the total, respectively. The remaining 3.2percent of capacity consists of renewable resources such as wind or biomass facilities.

It is expected that approximately 74 MW of wind capacity (228 MW nameplate), a 28 MW landfill gas facility and a 25 MW uprate to a wood-burning power plant will be in service before or during the 2012/2013 winter.

The current scheduled generator outages for the ISO-NE winter capacity weekly peak period total 439 MW in December, 126 MW in January and 1,345 MW in February, most of which are for annual generator inspections and could possibly be rescheduled to address reliability concerns.

Within the Existing-Certain category, approximately 188 MW of capacity is wind generation that is expected to be available at the time of peak demand. This reflects a 378 MW derate on-peak, from the total nameplate capability of 566 MW. Solar generation, though not considered impactive during winter evening peak periods, makes up 2 MW of on-peak capacity, derated from its nameplate capacity of 18 MW. Existing-Certain capacity also includes 1,622 MW of hydro-electric

[70] Passive Resources are defined as either On-Peak or Seasonal Peak Resources, the main difference being their performance hours. On-Peak Demand Resources provide their load reduction during non-holiday weekdays in December and January during the on-peak hours of 5:00 to 7:00 p.m. Seasonal Peak Demand Resources must reduce load during non-holiday weekdays when the Real-Time hourly load is equal to or greater than 90% of the most recent 50/50 System Peak Load Forecast for the applicable summer or winter season.

[71] Operating Procedure No. 4 is located on the ISO's web site at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[72] These active demand response resources can be used to help mitigate an actual or anticipated capacity deficiency. OP 4 Action 2 is the dispatch of Real-Time Demand Response Resources, which is implemented in order to maintain the full NPCC operating reserve requirements. Action 6, which is the dispatch of Real-Time Emergency Generation Resources, is implemented to maintain NPCC 10-minute operating reserve.

resources. This reflects a 421 MW derate on-peak, from the total nameplate capability of 2,043 MW. Biomass capacity in the Existing-Certain category totals 945 MW.

The method for determining the expected on-peak capacity for wind, solar, hydro, and biomass facilities depends on whether the resource is classified as intermittent or non-intermittent. Generally, run-of-river hydroelectric units, many of the biomass plants and all of the wind and solar resources are categorized within the intermittent category. The winter capability of intermittent units is equal to the median of net output during the winter reliability hours each day of the previous winter (October through May), as well as any winter hour with a shortage event.[73]

On-Peak Capacity Transactions

The forecast for 2012/2013 winter on-peak Firm capacity imports is 575 MW. These Firm capacity imports, which include 253 MW from Hydro-Québec and 322 MW from New York, have been contracted for delivery within the 2012/2013 FCM Capability Period.[74,75] A Firm capacity export of 100 MW is anticipated to be delivered via the Cross-Sound Cable (CSC) to New York (Long Island).

Transmission

Currently there are three significant transmission facilities scheduled for maintenance during the winter capacity period. Two of the outages impact post contingency operating requirements for power plants and the remaining transmission facility effects power transfers into Connecticut and between New York and New England. None of these outages are anticipated to impose noteworthy reductions to generator facilities or transfer limits. If unfavorable conditions develop, ISO-NE will coordinate the repositioning of outages as needed.

Though ISO-NE currently has numerous transmission projects underway, none are required to be completed before or during the winter assessment period to either maintain or enhance system reliability.

Operations

There are no significant environmental restrictions that would adversely impact system reliability or require special operating studies during the winter.

ISO-NE does expect the potential for various amounts of single fuel, gas-only power plants to be temporarily unavailable during extreme winter weather conditions or during force majeure conditions on the regional gas grid, and plans to mitigate these scenarios with supplemental commitment. ISO-NE continues to integrate new power supply sources, including new variable resources, into the electrical network. To facilitate system operation with potentially large amounts of wind power, SO-NE Operating Procedure No. 14 Appendix F - Wind Plant Operators Guide (OP 14F),[76] was developed and implemented.[77]

ISO-NE does not have any scheduled unit retirements, communicated project deferments or permanent derates scheduled for the winter 2012/2013 assessment period. New England does anticipate that, in the event of a full dispatch of demand resources during the 2012/2013 winter season, the response rate will be in the range of 85 percent of the full capacity obligation (CSO). This estimate is based on the December 2011 audits of dispatchable Demand Resources which demonstrated an aggregated performance of 84.9 percent of the CSO in place at that time. Those audits were conducted in late afternoons during the typical winter peak load ramp period. Performance could be lower depending on the time of the actual dispatch, as was experienced during the December 19, 2011 dispatch of Real Time Demand Resources. This dispatch was early on a Monday morning and there was essentially no prior indication that a dispatch would be necessary. During

[73] These are events under which ISO-NE operations experience either an operating reserve or capacity deficiency.
[74] The 2012/2013 FCM Capability Period is from June 1, 2012 to May 31, 2013.
[75] 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).
[76] The ISO Operating Procedure OP 14, Appendix F is located here at: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14f_rto_final.pdf.
[77] Under the FCM rules, the deliverability of external capacity imports must meet the same deliverability 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 the market participant also bears the associated risks of FCM non-deliverability penalties if it chooses non-Firm transmission.

the period of 100 percent CSO dispatch on 12/19/2011, the aggregate performance was 75.4 percent of CSO. It should also be noted that there has been variation in winter Demand Resource performance between dispatch zones, though there is insufficient data at this time to discern any predictive patterns.

Vulnerability Assessment

Though during the summer capacity period the region had received less rainfall than normal, but New England has not been undergoing a drought and drought conditions are not forecasted for the near future. New England will put into service one new SPS during this assessment period. The SPS is identified as the "Rumford Area Temporary SPS." This temporary SPS is required for a long duration construction outage in western Maine that will take approximately 18 months to complete. Following completion of the construction the SPS will then be permanently retired. The SPS function is to transfer trip a generator following the occurrence of a 115 kV contingency in western Maine. The SPS has completed all of the required New England and NPCC planning requirements for installation as a new SPS. It has been classified as a NPCC Type III SPS, which means that its failure to operate would only affect a local area.

ISO-NE has not identified areas of major concern regarding the reliability of its fuel sources, other than natural gas.[78] As previously noted, most of New England's gas-fired power plants are not dual-fuel capable, and most do not have Firm gas supply or transportation contracts. On days of extreme winter temperatures, single-fuel, natural gas-fired capacity is at risk of being unavailable due to fuel constraints. During the winter period in New England, the regional pipelines run full with gas targeted for use by the regional local distribution companies.[79] Therefore, on an extreme (weather) winter peak day, various amounts of single fuel, gas-only capacity are likely to be fuel constrained. This would result in ISO-NE committing oil and coal units that require lengthy notification timelines to supplement the known loss of gas-fired capacity under these types of winter weather scenarios, or during force majeure declarations on the regional gas grid. This creates operational challenges for near-term planning and real-time operations.

In addition to discussing the winter outlook with regional stakeholders, ISO-NE staff has also attended several regional fuel supply conferences and seminars. Access to and delivery of natural gas to the regional power generation sector continues to be a concern within New England during the winter months. ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability. ISO-NE continuously monitors the regional natural gas pipeline systems, via their Electronic Bulletin Board (EBB) postings. This ensures that emerging gas supply or delivery issues can be incorporated into and mitigated within the daily or day-ahead operating plans. Should natural gas issues arise, ISO-NE has predefined communication protocols in place with the Gas Control Centers of the regional pipelines and local distribution companies, 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 affecting the power generation sector:

- 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.[80] 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.
- 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.[81]

[78] As of late October 2012, regional inventories of distillate fuel oils (i.e. jet fuel, kerosene, diesel and No. 2 fuel oil) are considerably down from their 5-year historical averages. With the restarting of several east coast refineries, this situation is expected to improve prior to winter.
[79] Local Distribution Company is a retail gas distribution company that delivers natural gas to end users.
[80] 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.
[81] Appendix H of Market Rule No. 1 is located at: http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-h.pdf.

NPCC-New York

2012/2013 Winter Season: Assessment Area Summary

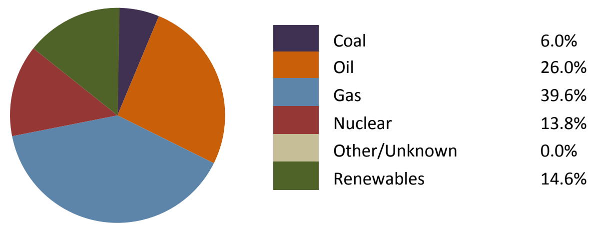
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**24,832**
Load-Modifying Demand Response	0
Net Internal Demand	**24,832**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	24,533
Actual Demand	23,901

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	1,424
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	32,418
Anticipated Resources	**33,841**
Anticipated Reserve Margin (%)	**36.28%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**33,841**
Prospective Reserve Margin (%)	**36.28%**
NERC Reference Margin Level (%)	**16.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

With the minimum Existing-Certain capacity of 31,877 MW and the expected peak of 24,832 MW, there is a wintertime reserve margin of at least 34.1 percent. This exceeds the 16.0 percent annual reserve margin set by the New York State Reliability Council (NYSRC).

The NYSRC has determined that an Installed Reserve Margin (IRM)[82] of 16.0 percent in excess of the NYISO Balancing Authority summer peak demand forecast for the Capability Year 2012/2013 is required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion. There are no foreseen issues or circumstances that could lead to detractions from seasonal projections.

Demand

The 2011/2012 actual peak demand occurred on January 3, 2012 and was 23,901 MW, 632 MW less than the forecast peak demand of 24,533 MW. The weather-normalized peak was 24,630 MW, 97 MW greater than the forecast peak. The primary drivers to the NYISO's peak load forecast are economic growth, energy efficiency impacts, weather trends, and geographic or structural economic changes in an area. There have been no significant changes in any of these drivers in 2012 compared to 2011.

The 2012/2013 winter peak demand forecast of 24,832 MW is 299 MW and 1.2 percent more than the 2011/2012 winter peak demand forecast of 24,533 MW.

Demand Side Management

Estimated energy efficiency impacts during the winter peak are 296 MW. Estimated enrollment of SCR resources for the winter capability period is 1,424 MW. Full deployment of the estimated resources may reduce the winter peak demand of 24,832 MW by up to 5.7 percent. The NYISO offers two demand response programs that support reliability: the Emergency Demand Response Program (EDRP)[83] and the Installed Capacity-Special Case Resource Program (ICAP/SCR).

[82] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2012 - April 2013" (December 2, 2011).
[83] Terms in upper case not defined herein have the meaning ascribed to them in the NYISO's Market Administration and Control Area Services Tariff.

Generation

For the 2012/2013 winter season the NYISO expects 42,201 MW of installed capacity with 31,877 MW of that classified as Existing Certain. Traditionally, New York generation mix has been dependent on fossil fuels for the largest portion of the installed capacity.

A new 216 MW nameplate wind facility, Marble River Wind Farm, is expected to come into service before the winter season. Since May 2012 several units have been retired. They are: Astoria GT 10 (May, 24.2 MW), Glenwood Units 4 & 5 (July, 111 & 105.5 MW), Far Rockaway Unit 4 (July, 106.2 MW) and Astoria GT 11 (July, 26.5 MW). All values are winter capacity ratings.

Since the 2012 summer season the Bayonne Energy Center, a 500 MW nameplate facility has come online while Dunkirk units 3 and 4 with nameplate capacity totaling 435 MW have retired. [5.5]The owner of the coal fired Cayuga units 1 and 2 has given notice of intent to mothball the units in January 2013. They are located in the Finger Lakes region of New York and total 306 MW of winter capacity. [5.6]No short term impacts due to capacity changes are expected in New York.

Installed capacities total: 1,579 MW for wind, 32 MW for solar, 4,685 MW for large hydro, 1,005 MW for run-of-river hydro, 92.9 MW for methane gas and 295.4 for refuse and wood. For the 2012/2013 winter season these capacities are de-rated 70 percent for wind to 473.7 MW, 84 percent for solar to 5 MW, 2 percent for large hydro to 4591.3 MW, 45 percent for run-of-river hydro to 552.8 MW, 16.6 percent for methane gas to 77.5 MW and 8.05 percent for refuse and wood to 271.6 MW.

On-Peak Capacity Transactions

The NYISO projects net imports into the New York Balancing Authority area of 1,100 MW during winter 2012/2013. 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.

Transmission

The Moses-Massena MMS2 230 kV line will be out of service for the 2012/2013 winter due to a breaker failure at the Massena switchyard. Due to a transformer failure, the Neptune DC cable will operate at half capacity for the winter season. The Beck-Packard BP76 230 kV line is expected to return to service by January, 2013. There are no foreseen reliability issues associated with these outages.

Operations

The NYISO routinely conducts a winter operating study for the November 1 through April 30 winter capability period. There were no unique operational problems observed from these studies. NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (flywheel and batteries). These resources are integrated such that no unique operational procedures are required.

The use of demand resources are fully integrated into the policies and procedures of the NYISO. The program design promotes participation and the NYISO expectation is for full participation. Further control actions are outlined in NYISO policies and procedures. There is no limitation as to the number of times a resource can be called upon to provide response.

Vulnerability Assessment

For the 2012/2013 winter season there are no specific operational concerns for extended drought conditions, long-term generator outages, unavailable demand response, increases in variable generation or environmental impacts.

Recent capacity additions or enhancements use natural gas as the primary fuel. While some existing generators in southeastern New York have "dual-fuel" capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the winter period.

NYISO has adopted the New York State Gas-Electric Coordination Protocol as Appendix BB[84] 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.

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[4] New York State Gas-Electric Coordination Protocol, Attachment BB to the NYISO Open Access Tariff (OATT), June 30, 2010.

NPCC-Ontario

2012/2013 Winter Season: Assessment Area Summary

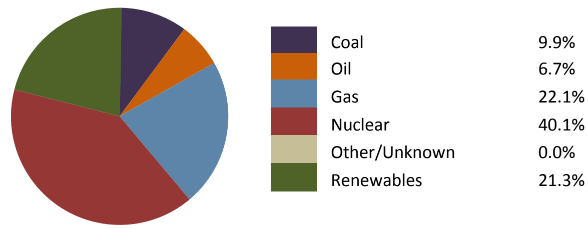
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**22,087**
Load-Modifying Demand Response	0
Net Internal Demand	**22,087**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	22,311
Actual Demand	21,847

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	1,315
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	31,404
Anticipated Resources	**32,719**
Anticipated Reserve Margin (%)	**48.14%**
Existing-Other and Future-Other Capacity	630
Prospective Resources	**33,349**
Prospective Reserve Margin (%)	**50.99%**
NERC Reference Margin Level (%)	**20.40%**

Assessment Area Capacity Mix



Planning Reserve Margins

Ontario is projecting an adequate Planning Reserve Margin during the 2012/2013 winter. All Planning Reserve Margins (Existing-Certain and Net-Firm Transactions, Anticipated, and Prospective Planning Reserve Margins) vary between 39.2 percent and 51 percent all well above target levels over this period for normal weather conditions. The reserve margin target determined on the basis of the IESO's requirements for Ontario's self-sufficiency is 19.7 percent.

Before the winter of 2012/2013, it is anticipated that there will be more than 1,700 MW of capacity added to the grid, comprising two refurbished nuclear units with a capacity of 1,500 MW returning to service, and more than 200 MW of new grid-connected renewable generation. Generation projects providing additional capacity are expected to be online before the winter 2012/2013 season. Though some delays are possible, Ontario meets the reserve margins target, regardless, with the existing generation capacity.

The IESO addresses winter extreme weather conditions by conducting planning studies using the most severe weather experienced over the last 31 years. Adequacy assessments show that Ontario will have sufficient reserves over the entire winter period.

Demand

The peak demand forecast for the last winter was 22,311 MW under Normal weather and 23,582 MW under extreme weather. The actual (not weather-corrected) peak demand was 21,847 MW. Actual peak demand was slightly lower than the normal weather forecast peak, with actual weather conditions fairly close to normal weather scenario. There was no demand response at the time of the system peak so weather corrected peak demand was only 0.3 per cent different from the forecasted peak.

This winter's peak demand forecast is 22,087 MW which is lower than the peak demand forecast for the winter of 2011/2012. Peak demand is expected to be lower due to four main factors. The economy remains stagnant with little growth in the industrial sector. Residential and commercial load would increase due to the significant level of construction activity. However, that underlying growth will be more than offset by the increase in embedded generation, conservation and customers subject to time-of-use rates.

Demand-Side Management

There are a number of conservation initiatives developed by distributors and the Ontario Power Authority, which are decremented from demand. However, none of these are included as demand response programs.

The IESO has just over 1,850 MW of demand response capacity of which roughly 1,315 MW is deemed to be reliably available at the time of system peak. All of the demand response programs within the IESO's service area are market-driven programs and are dispatched based on market conditions. There are price and demand triggers that both need to be met in order to deploy these resources. These triggers are calculated to meet a certain number of activations per month.

The Dispatchable Loads bid into the market and are dispatched off like any resource. This program has a total capacity of roughly 900 MW. The DR3 program contracts loads that are dispatched off the system based on the supply cushion – the difference between demand and supply. This program has a capacity of 525 MW. Four other programs provide an additional 425 MW of capacity.

Generation

The amount of Existing Certain resources is between 28,984 MW and 30,042 MW over the three months, December 2012 to February 2013. Existing-Other ranges from 480 to 680 MW and Existing Inoperable totals 27.5 MW. The primary fuel of existing resources by installed capacity is nuclear (34 percent), followed by gas/oil (28 percent) and hydroelectric (23 percent). Two refurbished nuclear units (1,500 MW) and two new wind farms (214 MW) are expected to be added prior to the winter season. Atikokan coal unit (211 MW) biomass fuel conversion is underway.

Two refurbished nuclear units will return to service and 214 MW of wind generation will be added before winter. A coal unit will go out of service and biomass fueled Thunder Bay Condensing Turbine (40 MW) is expected to be added during winter. Since the winter of 2011/2012 there has been 300 MW of new embedded generation contracted to begin commercial operation.

For wind, 586 MW is expected at time of winter peak out of a maximum capacity of 1,725 MW. There is no grid-connected solar in Ontario at this time. For hydro, 6,012 MW out of a maximum of 7,947 MW is expected on-peak. For biomass, 44 MW out of 122 MW installed capacity is expected at the time of the winter peak.

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. IESO also participates in the NPCC Simultaneous Activation of Reserve program which includes PJM, NYISO, ISO-NE and New Brunswick.

Transmission

Planned outages may result in some transfer capability reductions but they are not expected to have any impact on the load supply. The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. Completion of this project will increase the transfer capability between the Niagara region to the rest of the Ontario system. Under the conditions expected for this winter, studies show that the system is adequate to meet expected demands without this reinforcement.

Operations

With the addition of nuclear and variable baseload generation to the grid combined with anticipated low off-peak electricity demands, Ontario will likely continue to experience SBG (Surplus Baseload Generation) conditions.

A lack of direct control over a number of factors that contribute to SBG, such as temperature, other weather parameters, consumption, and lack of generation and load response to market prices, poses challenges in handling SBG situations. These events will need to be managed in the short term until baseload generation begins to decline when nuclear refurbishment programs get underway later in the decade.

With the forecast increase in SBG, an increase in out-of-market control actions is foreseen such as minimum hydro dispatch and nuclear maneuvers, to be required in order to manage the surplus, extending beyond the typical market actions which include exports. With wind and solar becoming more prominent resources on the electricity system, the need for maximum flexibility from all resources has become integral for the reliable and efficient operation of the grid. When variable generation becomes dispatchable, additional flexibility will be available to diminish the frequency of out-of-market control actions for SBG.

Vulnerability Assessment

The hydroelectric production was low from May to July 2012. The hydroelectric forecast was reduced for the fall months. However, it is expected that the production may bounce back to median levels for the winter months. Ontario generates its forecasts using median conditions for hydroelectric generation and does not expect any impacts from drought for winter 2012/2013.

The Atikokan coal unit will be on a long–term outage during winter and beyond for conversion to biomass. The IESO is working with Hydro One and OPG to accommodate the Atikokan coal shutdown and conversion project. Work includes completion of planned maintenance on other critical equipment to support the outage, and ensuring plans to manage high-voltage situations are sufficient to cover the duration of the Atikokan outage.

The IESO includes a quantity of demand response termed “Reliably Available Capacity” in its reliability analysis. This does not represent the total registered capacity of demand response programs. For market-based programs, the IESO utilizes historical information to ascertain the amount of demand response capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, the IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity.

There are restrictions on how many times Demand Response 3 can be deployed. However there are price and demand triggers that both need to be met in order to deploy these resources. These triggers are calculated to meet a certain number of activations per month.

About 3,200 MW of coal generation has been shut down since 2010. Replacement capacity has come from new gas generation as well as from renewable generation. The existing coal fleet, though running at vastly reduced levels from previous years, provides the IESO with desirable flexibility, such as quick ramping and operating reserve, under all market conditions. As Ontario’s coal-fired generation is shut down over the next two years, its associated flexibility will be lost. Therefore, future capacity additions should also possess this flexibility to help facilitate the management of maintenance outages, provide effective ramp capability, supply operating reserve and even provide regulation when necessary.

Regarding gas-electric interdependency, there are communication protocols in effect between the IESO and gas pipeline operators to manage and share information under tight supply conditions in either sector (gas or electricity).

NPCC-Québec

2012/2013 Winter Season: Assessment Area Summary

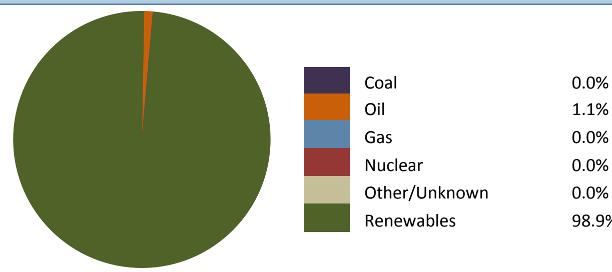
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**37,543**
Load-Modifying Demand Response	1,830
Net Internal Demand	**35,713**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	37,153
Actual Demand	35,481

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	1,830
Net Capacity Transactions (Firm and Expected)	183
Existing-Certain and Future-Planned Capacity	39,606
Anticipated Resources	**41,619**
Anticipated Reserve Margin (%)	**16.54%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**41,619**
Prospective Reserve Margin (%)	**16.54%**
NERC Reference Margin Level (%)	**9.60%**

Assessment Area Capacity Mix



Planning Reserve Margins

The Québec Assessment Area is projecting adequate Planning Reserve Margins for the 2012/2013 winter peak period, with an Anticipated Reserve Margin equal to 10.9 percent. This Planned Reserve Margin is above the Area Reference Reserve Margin level of 9.6 percent and shows that the Québec Area has sufficient resources to meet its winter peak load forecast. The Québec capacity is predominately hydro (93 percent), so the Reference Reserve Margin level is lower than for systems where the generation makeup is different.[85]

The Planning Reserve Margins projected throughout the 2012/2013 winter season result mostly from the commissioning of additional resources such as La Sarcelle hydro Generating Station (100 MW) along with wind and biomass resources. In fact, more than 760 MW of additional wind power (with an estimated 30 percent capacity value at peak) and about 110 MW of additional biomass will be in service for the 2012/2013 winter peak period. Moreover, additional capacity (150 MW) in the interruptible load program and an additional capacity contribution from existing Hydro-Québec Production (HQP) wind farms (32 MW) contribute to this adequate level of projected Reserve Margins.

Demand

The Hydro-Québec System is winter peaking because a large amount of space heating load is present during Winter Operating Periods. The all-time internal peak hourly demand is 37,717 MW which occurred on January 24, 2011. The internal demand forecast for the 2012/2013 winter peak period is 37,543 MW forecasted for January 2013. This forecast is 390 MW higher than the 2011/2012 winter forecast of 37,153 MW (+1.05 percent). The difference reflects slightly growing demand in all sectors, particularly the industrial sector.

The actual peak demand which occurred on January 16, 2012 was 35,481 MW. The difference between the actual peak demand and the forecasted demand is explained mainly by weather conditions. Winter 2011/2012 was remarkably warmer than the average. In Montréal (the main load area) average temperatures were 3.4°C (6.1°F) higher than normal temperatures. This was the warmest winter since 2001/2002.

[85] The Reference Reserve Margin Level is drawn from the most recent Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on November 29, 2011.

Demand-Side Management

Demand Response (DR) programs in the Québec Area specifically designed for peak-load reduction during winter operating periods and are considered as interruptible demand programs (for large industrial customers). DR totals 1,580 MW for the 2012/2013 winter season. In this assessment, DR resources are treated as supply-side resources. These resources are usually used in situations where load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. Moreover, total Energy Efficiency/Conservation (Demand Side Management) is included in the forecasted load and accounts for 1,780 MW for the 2012/2013 winter peak period.

Generation

Resources being considered in this assessment for the winter 2012/2013 period are shown below:

- Existing-Certain: 39,606 MW
- Existing-Inoperable: 547 MW
- Existing-Other: 0 MW
- Future-Planned: 0 MW

Most generation in the Québec Area is hydro (93 percent of Installed Capacity) owned and operated by Hydro-Québec Production (HQP). Variable resources include wind resources, owned and operated by Independent Power Producers and some biomass. Installed nameplate capacity is expected to be 1,814 MW in December 2012. A small amount of capacity (281 MW) is generated by biomass. Two fossil fuel generating stations have been permanently retired since March 2012. The Tracy G.S. (450 MW) which was mothballed in the previous assessment is now permanently retired and the La Citière G.S. (280 MW) has been retired since May 2012. Moreover, the Gentilly-2 nuclear G.S. (675 MW) will be retired for decommissioning at the end of 2012. In addition, La Sarcelle G.S.'s last unit (50 MW hydro) should be in service later in winter or spring 2013. It is not assumed to be in service for this winter assessment.

Maximum capacity for hydro resources is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions. Biomass and wind IPPs have signed contractual agreements with Hydro-Québec. Therefore, maximum capacity and expected on-peak capacity of biomass are equal to contractual values. These represent almost 100 percent of nameplate capacity. As for wind resources, maximum capacity is set equal to contractual capacity. The capacity contribution of wind power generation at peak is estimated to be 30 percent of nameplate capacity.

On-Peak Capacity Transactions

The Québec Area will need to purchase about 600 MW on short term markets to ensure resource adequacy for the 2012/2013 Winter Operating Period. All capacity purchases needed to ensure resource adequacy for the 2012/2013 winter operating period will be backed by Firm contracts for both generation and transmission. For exports, a total of 398 MW with neighboring areas are backed by Firm contracts.

Transmission

Most significant transmission facilities are expected to be in service for the winter operating period. Transmission maintenance outages are scheduled during summer operating periods because of the system’s winter-peaking characteristic. Planned transmission outages are normally completed by December 1.

Synchronous Condenser CS23 at Duvernay substation in the Montréal area, which has been out of service since June 2008 due to a major transformer fault, will be back in service for the 2012/2013 Winter Operating Period. This will enhance transmission capability on the Southern Interface of the load area of the Québec system.

Transmission projects now under way and scheduled in service for this winter peak period concern mainly wind generation integration (seven projects totaling 760 MW), 120 and 230 kV Bécancour subsystem reinforcement and satellite substation integration (three substations). No delays are expected.

There are no specific major projects needed to maintain or enhance system reliability during the 2012/2013 winter. There are a number of regional projects now under way: the Limoilou 230/25 kV substation in Québec City, the l'Anse-Pleureuse 230/25 kV substation, the Neubois 120/25 kV substation and the Bécancour 230 and 120 kV system reinforcements are scheduled in service for fall 2012.

Finally, Hydro-Québec TransÉnergie (HQT) is proposing to install a new generation rejection Type III SPS at Bersimis-1 and 2 Generating Stations. The SPS should be operational before the winter. The SPS is required because a double-circuit 315-kV transmission line will be unavailable during work done to integrate three wind power plants on the Bersimis sub-system. Without the SPS, this outage would cause restrictions at Bersimis-1 and 2.

Operations

No particular operating problems concerning transmission equipment have been observed for the coming 2012/2013 Winter Operating Period. Despite the retirement of two fossil fuel generating stations, a significant additional amount of capacity (hydro, wind and biomass), demand response and energy efficiency were added to the system, so these withdrawals have no impact on the system's reliability.

Integration of wind generation resources is ongoing in Québec. There will be about 3,600 MW integrated into the system by 2015; for the 2012/2013 operating period, it is expected that 760 MW of additional nameplate capacity will be placed into service, bringing the total wind nameplate capacity to 1,814 MW. This has not yet led to any special System Operating Procedures. Total generation capacity has actually grown for the 2012/2013 winter, despite fossil fuel retirements. However, peaking capability has been reduced with the retirement of La Citière jet turbine G.S. (280 MW) which, when manned, was usually available within 10 minutes.

Interruptible Load

Interruptible load programs used to meet peak demand are planned with participating industrial customers, who are contacted before the peak period (generally during fall) 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.

There are two different load response programs in Québec and each program has different options. There are some limitations or restrictions on calling demand response. Firstly, these programs are not available during summer operating periods. In winter, some options are available twice a day; others are available once a day. There is a maximum number of calls and a maximum number of interruption hours over a year. Calls must be made 2 to 18 hours in advance depending on the options to be used. The Load Serving Entity in Québec accounts for these restrictions when evaluating resource adequacy in the Area.

Unusual Operating Conditions

Presently, Hydro-Québec TransÉnergie (HQT) has a 735-kV current transformer (CT) replacement program running for the next two years. CTs that will not be replaced before winter will be subject to a restricted-access area due to safety issues that could limit operator interventions in such substations until the replacements are completed; this will not significantly impact operations.

Vulnerability Assessment

Given the importance of hydroelectric resources within the Québec Area, an energy criterion has been developed to assess its energy reliability, stating that sufficient resources should be available to run through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively, and having a 2 percent probability of occurrence (system consumption was approximately 186 TWh in 2011). Normal hydro conditions are projected for the winter season and reservoir levels are expected to be sufficient to meet both peak demands and daily energy demand.

PJM

2012/2013 Winter Season: Assessment Area Summary

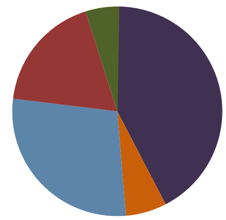
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**130,222**
Load-Modifying Demand Response	0
Net Internal Demand	**130,222**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	130,711
Actual Demand	130,222

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	581
Net Capacity Transactions (Firm and Expected)	217
Existing-Certain and Future-Planned Capacity	181,669
Anticipated Resources	**182,467**
Anticipated Reserve Margin (%)	**40.12%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**182,467**
Prospective Reserve Margin (%)	**40.12%**
NERC Reference Margin Level (%)	**15.60%**

Assessment Area Capacity Mix



Planning Reserve Margins

The PJM projected (existing and anticipated margins are the same) reserve margin for winter 2012/2013 is 40.1 percent. This level is well in excess of the PJM Required Reserve Margin[86] of 15.6 percent. The Reserve Margin calculation includes total forecasted load, Existing Certain generating resources, net transfers and Energy Efficiency treated as a resource. Demand-Side management is not included in the reserve margin calculations during this winter.

Demand

The PJM RTO 2011/2012 winter peak was 122,565 MW that occurred on January 3, 2012, hour ending 1900. On a weather-normalized basis, the PJM RTO 2011/2012 winter peak forecast was 130,711 MW. The difference can be attributed to a relatively mild winter in most of the PJM region. The forecast for the 2012/2013 PJM RTO winter peak is 130,222 MW. The combination of the new economic driver model and a downward revision to the economic outlook for the PJM area has resulted in almost the same peak and energy forecasts compared to last year’s report. This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment).

Demand-Side Management

The total amount of Energy Efficiency for the PJM area expected to be available on peak for winter 2012/2013 is 581 MW. PJM Demand Response (DR) is not secured for the winter season except for DR used for operating reserves.

Energy Efficiency programs included in the 2012/2013 load forecast are impacts approved for use in the PJM RPM. Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B - Energy Efficiency Measurement & Verification.[87] DR used for reserves is limited by the RFC standard BAL-002-RFC-02 to 25 percent of the Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,000 MW during a winter peak day.

[86] http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx.
[87] http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

Generation

There is 181,669 MW of Existing-Certain generation in PJM to meet this winter's peak load. There is 4,825 MW of Existing-Other generation in PJM this winter. This amount is composed of wind and solar derates only. No Existing-Inoperable generation is accounted for in PJM. The predominant source of fuel in PJM is coal at approximately 42 percent of total Existing-Certain capacity. Next is natural gas at 26 percent of total Existing-Certain capacity and nuclear at 18 percent of total Existing-Certain capacity. No capacity resource changes are expected though the winter of 2012/2013.

Please see the table below for PJM generator retirements since May 2012.

Unit	Capacity (MW)	Transmission Zone	Age (Years)	Fuel Type	Actual Deactivation Date
Walter C Beckjord 1	94	DEOK	59	Coal	May-2012
Buzzard Point East Banks 1, 2, 4-8	112	PEP	39	Diesel	May-2012
Buzzard Point West Banks 1-8	128	PEP	39	Diesel	May-2012
Eddystone 2	309	PE	49	Coal	May-2012
Elrama 1	93	DUQ	59	Coal	June-2012
Elrama 2	93	DUQ	59	Coal	June-2012
Elrama 3	103	DUQ	57	Coal	June-2012
Kearny 10	122	PSEG	39	Natural Gas	June-2012
Kearny 11	128	PSEG	40	Natural Gas	June-2012
Niles 2	108	ATSI	58	Coal	June-2012
Benning 15	275	PEP	39	Oil	July-2012
Benning 16	275	PEP	35	Oil	July-2012
Crawford 8	319	ComEd	50	Coal	August-2012
Crawford 7	213	ComEd	53	Coal	August-2012
Fisk Street 19	326	ComEd	52	Coal	August-2012
Albright 1	73	APS	59	Coal	September-2012
Albright 2	73	APS	59	Coal	September-2012
Albright 3	137	APS	57	Coal	September-2012
Armstrong 1	172	AP	53	Coal	September-2012
Armstrong 2	171	AP	52	Coal	September-2012
Bay Shore 2	138	ATSI	53	Coal	September-2012
Bay Shore 3	142	ATSI	48	Coal	September-2012
Bay Shore 4	215	ATSI	43	Coal	September-2012
Eastlake 4	240	ATSI	55	Coal	September-2012
Eastlake 5	597	ATSI	39	Coal	September-2012
R Paul Smith 3	28	AP	64	Coal	September-2012
R Paul Smith 4	87	AP	43	Coal	September-2012
Rivesville 5	35	APS	68	Coal	September-2012
Rivesville 6	86	APS	60	Coal	September-2012
Vineland 10	23	AE	41	Coal	September-2012
Willow Island 1	51	APS	63	Coal	September-2012
Willow Island 2	138	APS	51	Coal	September-2012
Niles 1	109	ATSI	58	Coal	October-2012
Elrama 4	171	DUQ	51	Coal	October-2012
Potomac River	482	PEP	62	Coal	October-2012
Total Deactivated:	**5,866**	-	-	-	-

No additional units are expected to retire during the winter 2012/2013 assessment period. Any addition of new generation or generator uprates adds to the PJM reserve margin. Any generation retirements subtracts from the PJM reserve margin.

The nameplate value of wind generators in PJM for this winter is 5,400 MW and the on-peak expected value is 700 MW. The nameplate value for solar units in PJM is 103 MW and the on-peak expected value is 39 MW. Hydro and biomass units are not derated. 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.

Capacity Transactions

All transactions are Firm for both specific generation and transmission. No currently accepted Firm contracts end during the 2012/2013 winter peak season. PJM has no reliance on outside assistance for emergency imports. There have been no addition of import/export capabilities for the 2012/2013 winter.

Transmission

There are no project delays or temporary service outages for transmission facilities (lines or transformers) that will impact reliability during this winter. No new transmission projects are needed to go in service during this winter to maintain reliability.

Operations

PJM performs both an Operations 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 processes incorporate announced retirements into the PJM Regional Transmission Planning Process. Planning and Operation staff analyze the need to implement RMR contracts to extend the retirement date until transmission reinforcements are placed into service. Additional Regional Transmission Expansion Plan (RTEP) projects have been identified based on projected capacity reductions. No general operational concerns for the coming 2012/2013 winter season have been identified in PJM.

PJM staff continues to manage the impact of approximately 16,600 MW of announced generation retirements and an additional 6,020 MW of projected retirements through 2018, mostly resulting from environmental legislation (approximately 5,700 MW retirement scheduled in 2012).

Vulnerability Assessment

PJM has very little hydro generation and reservoir levels are adequate. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM.

PJM has developed a Wind Power Forecast tool and visualization to assist operations. This tool enhances the operator's ability to more accurately project how much power can be expected from wind resources. Expected values typically provide forecasts for near real-time and hourly time increments.

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.

SERC-E

2012/2013 Winter Season: Assessment Area Summary

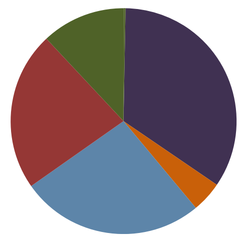
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**43,150**
Load-Modifying Demand Response	1,504
Net Internal Demand	**41,647**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	42,459
Actual Demand	40,151

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	1,430
Existing-Certain and Future-Planned Capacity	54,307
Anticipated Resources	**55,737**
Anticipated Reserve Margin (%)	**33.83%**
Existing-Other and Future-Other Capacity	52
Prospective Resources	**55,789**
Prospective Reserve Margin (%)	**33.96%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

Reserves are appropriate for providing an adequate and reliable power supply during the 2012/2013 winter. Entities do not use a regional/reporting area target or Reserve Margin criteria. No operational problems are anticipated that would detract from these projected Reserve Margins.

Demand

The 2011/2012 winter actual demand was 40,151 MW while the peak Total Internal Demand forecast for 2011/2012 was 42,459 MW. The differences between these figures are primarily due to mild seasonal weather and reduced demands stemming from lingering economic conditions. This winter's peak demand forecast is projected to be 43,150 MW, which is 1.6 percent higher than the prior year's forecast. Increases are due to anticipated economic growth and normalized winter conditions. Some entities within the reporting area are updating their forecasting models for the most recent regional and local economic projections. .

Demand-Side Management

Demand Response and Energy Efficiency programs are projected to be 1,687 MW and 496 MW, respectively. Existing Demand Response resources are primarily used for reducing peak loads associated with system emergencies and maintaining adequate capacity reserves.

Generation

Companies within the SERC-E reporting area expect to have 52,353 MW of Existing-Certain, 10 MW of Existing-Other, and 64 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Coal is the primary source of fuel within this area, representing 35 percent of Existing-Certain Resources, with the next largest fuel source of gas/dual fuel at 27 percent. Additionally, 2,389 MW of Future-Planned resources are projected to be added leading up to and during the period. This new generation capacity is scheduled to come on-line to offset planned retirements. By December 2012, approximately 90 MW of reduced generation is expected during the winter due to unit retirements. As a result of the recently finalized environmental regulatory requirements, entities will continue to assess the risk on the system and plan accordingly to meet demand. No additional generation retirements have been announced. Individual entity's internal company discussions have included scenario planning and mitigation measures. Mitigation options must be explored and considered as part of any decision to retire existing generating units.

Entities have scheduled approximately 1,445 MW of new generation in-service prior to the 2012/2013 winter season. A new combined cycle facility is scheduled to be in-service by October 2012 and will be rated for a net output of 620 MW. This generation will offset previously retired coal-fired generation. In January of 2013, 1,049 MW of new generation is scheduled to be in-service. System upgrades are being made to accommodate the new generation. Before December 2012, entities plan to retire 1,755 MW of generation, approximately 68 percent of retirements are from coal-fired generation. Approximately, 2,300 MW are expected to be off-line throughout the period.

A hydro unit rated at 50 MW is reported to be off-line for an extended outage. Entities continue to assess long-term outages and report significant changes to SERC staff throughout the year. Behind-the-meter and distributed generation are reported to be 0 MW. However, entities expect 630 MW of non-traditional resources for the winter period.

For the upcoming winter season, companies within the SERC-E reporting area expect to have 97 MW of biomass, 28 MW of solar, and 6,139 MW of hydro/pumped storage capacity on-peak. SERC does not collect the nameplate output of the units, so no maximum capacity MW is available. Overall, variable resources are limited within this area. However, they are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the regulatory standards and their ability to maintain flexibility for long-term resource decisions. As required, entities will continue to evaluate these and other renewable resources as part of their integrated resource planning process.

Capacity Transactions

Entities within the SERC-E reporting area expect net capacity transaction as listed in the summary table for the 2012/2013 winter. All resources are used in Reserve Margin calculations for the reporting area. Of all imports/exports, very few are associated with Liquidated Damages Contracts (LDCs), in which the contracts are considered 100 percent “make-whole.”

To meet Planning Reserve Margins during the period, entities within the SERC-E reporting area do not rely on resources outside the region for emergency imports, reserve sharing, or outside assistance/external resources.

Transmission

The existing transmission projected in-service dates are not at risk for the assessment period.

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 specific projects have been identified that would maintain or enhance reliability for the winter period.

Operations

For hydro units, lake levels are carefully managed. To the extent weather conditions and inflows permit, entities manage hydro capacity limitations during seasonal peak load periods.

Overall, there are no other unusual operating conditions anticipated that could impact reliability for the winter.

Vulnerability Assessment

Resource adequacy studies help determine entity Reserve Margins in the reporting area. 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. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These operational studies may be performed annually using input provided from Generator Operators. As conditions warrant, entities may need to perform additional assessments to mitigate challenging conditions that may occur to the system. Entities report that historical studies have determined that a minimum reserve of 12 percent is adequate for reliability.

Entities 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-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, 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 on 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.

SERC-N

2012/2013 Winter Season: Assessment Area Summary

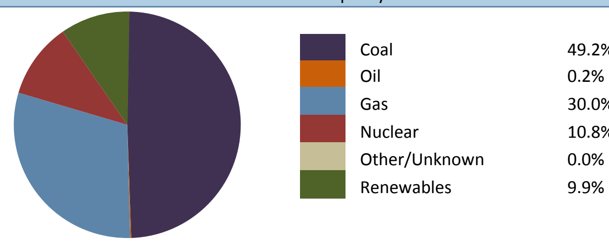
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**45,081**
Load-Modifying Demand Response	1,592
Net Internal Demand	**43,489**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	47,123
Actual Demand	39,580

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-236
Existing-Certain and Future-Planned Capacity	57,831
Anticipated Resources	**57,595**
Anticipated Reserve Margin (%)	**32.44%**
Existing-Other and Future-Other Capacity	6,290
Prospective Resources	**63,885**
Prospective Reserve Margin (%)	**46.90%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Footprint

Assessment Area Capacity Mix



Planning Reserve Margins

The SERC-N Assessment Area had planned for adequate Planning Reserve Margins during the 2012/2013 winter season and this is now further enhanced by lower projected loads. Entity results show that they are planning for reserves of at least 15-17 percent for the upcoming winter. Reserves forecast for the season are adequate, assuming typical weather and expected operating conditions. Currently there are no potential issues that could lead to detraction from reported projections.

Demand

The difference between the 2011/2012 winter peak demand forecast of 47,123 MW and the actual of 39,580 MW is primarily due to extremely mild weather conditions. The impact of a new rate structure on consumer behavior may also have had an effect. This winter’s peak demand forecast is 45,081 MW. The decrease from the prior year’s forecast is due to reduced load expectations. Assumptions have been adjusted for normal weather and current economic conditions for both the US and regional economies. Since the start of the economic recession, some entities reported that they have significantly adjusted their long-term models and enhanced near-term hourly forecast models.

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 1,592 MW and 139 MW, respectively. These load control programs allow entities to reduce demand and control voltage as needed for reliability purposes during peak loads. Demand Response is projected to be 3.5 percent of Total Internal Demand for the upcoming winter, for a 0.7 percent increase from the 2011/2012 winter season. The primary source of current Demand Response is a direct load control (DLC) program and an interruptible product portfolio.

Generation

Entities within the SERC-N reporting area expect to have 57,843 MW of Existing-Certain, 2,576 MW of Existing-Other, and 152 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during the 2012/2013 winter season. Coal is the primary fuel source within this area, representing 43.3 percent of Existing-Certain resources. The next largest fuel source for generation is gas/dual fuel with 33.3 percent of Existing-Certain resources. No Future-Planned resources are planned for the season. Between May and October 2012 there were 2,209 MW of coal-fired and hydro generation retirement, deferments, derates or other reductions. No additional capacity reductions are expected to occur during the winter season.

16 MW of Biomass, 156 MW of wind, and 6,389 MW of hydro/pumped storage are expected on-peak. The capacity values of wind contracts are usually based on contract terms with an assumed contribution at system peak of 12 percent of the wind generator nameplate ratings. This factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area. The contribution from customer-owned solar resources is based on solar insolation values at the time of the 2012/2013 winter peak.

Hydro capacity projections are based on modeling the competing requirements for management of the Tennessee River system. Balancing these requirements and factoring in anticipated weather conditions for the winter season allows estimation of energy production from the conventional hydro facilities.

Capacity Transactions

Net capacity transactions for the SERC-E Assessment Area are shown in the summary table above. The majority of these imports/exports into and out of the SERC-N Assessment Area are backed by Firm contracts for both Firm specific generation and transmission and do not include "make-whole provisions." Imports and exports have been accounted for in the Reserve Margin calculations for the reporting area.

Contingency reserves and emergency imports are obtained from a variety of resources such as Midwest ISO (under Attachment RR of the Midwest ISO ancillary services market tariff), together with 350 MW from PJM and 1,347 MW from the TEE Contingency Reserve Sharing Group (TCRSG). Entities are not anticipating additional import/export capabilities for the winter season.

Transmission

If week-ahead, real-time, or next day operating studies reveal potential reliability issues, action plans such as operational guides exist to address and mitigate the issue. Local area generation may be re-dispatched or transmission elements reconfigured to alleviate anticipated next contingency overloads. No transmission issues have been identified that will impact reliability during the 2012/2013 winter season.

Operations

Routine operating studies (bi-annual load forecast study; monthly, weekly, and daily operational planning efforts; annual assessment of winter peak and temperature, etc.) are performed to assess the system. These studies take into consideration weather, demand, unit availability, and upcoming capacity reductions to help to address risk. Based on the results of these studies entities do not anticipate operational problems.

Operational guides are also in place to mitigate impact of variable resources as needed. Net scheduled interchanges plus the operating minimum on all the generators are assessed to address low minimum load conditions. System operators have the authority to take units off-line to address generation operating minimum issues as needed.

There are no unusual operating conditions anticipated that would impact reliability for the winter season.

Vulnerability Assessment

Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. No system reliability concerns for the season have been identified in the latest resource adequacy studies. Resource availability, fuel availability, hydro and reservoir conditions are expected to be normal during the winter season. Preventative actions such as maintaining adequate fuel inventories, purchasing incremental fuel supplies, and obtaining dual fuel options and additional purchased power contracts, will help ensure operational concerns are not an issue for the season.

Entities are aware of potential risks associated with current and pending environmental regulations/limitations. In order to maintain compliance entities perform studies, re-establish operational procedures, and implement projects. Outage coordination procedures assist in avoiding or mitigating system reliability impacts. No reliability impacts are anticipated for the upcoming winter season.

Having a diverse portfolio of suppliers is common within the SERC-N 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 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 reroute deliveries among themselves. Some stations having coal delivered by rail can also use trucks to supplement deliveries.

Entities 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 winter season. Multiple entities have contracts for local coal from area mines. In the event of a potential supply or transportation disruption, entity processes may include the delay or cancelation of planned unit maintenance outages or derates.

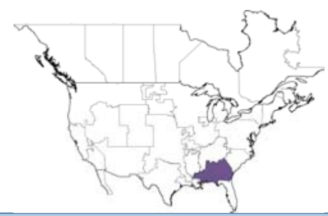
SERC-SE

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**45,620**
Load-Modifying Demand Response	1,882
Net Internal Demand	**43,738**

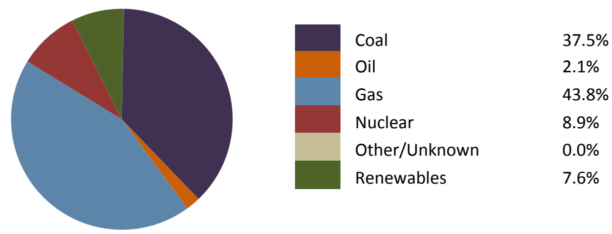
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	44,259
Actual Demand	42,811

Assessment Area Footprint



2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-2,262
Existing-Certain and Future-Planned Capacity	67,102
Anticipated Resources	**64,840**
Anticipated Reserve Margin (%)	**48.25%**
Existing-Other and Future-Other Capacity	2,412
Prospective Resources	**67,253**
Prospective Reserve Margin (%)	**53.76%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Capacity Mix



Planning Reserve Margins

The SERC-SE Assessment Area is projecting an adequate Planning Reserve Margin during the 2012/2013 winter period. Entities do not adhere to any regional/reporting area targets or the NERC Reference Reserve Margin criteria. However, the State of Georgia requires maintaining at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) Reserve Margin levels for investor-owned utilities or the largest operating company within the state. Through the system's intercompany interchange contract, this Reserve Margin requirement has been applied to all system operating companies and is verified triennially via resource adequacy studies for the entire system. Winter reserves for this summer-peaking area are anticipated to be adequate due to reductions in load forecast resulting from the recent recession and continued economic recovery, assuming typical weather and operating conditions. There are no known operational issues or circumstances expected to detract entities from these projections.

Demand

Increases from the 2011/2012 winter peak demand forecast of 44,459 MW and this winter's peak demand forecast, which is projected to be 45,620 MW, are primarily due to economic recovery conditions. The 2011/2012 winter actual peak demand of 42,811 MW was lower than the 2011/2012 winter peak demand forecast. Differences in demand were due to warmer than normal weather. A change in the load class composition due to the economic recovery has increased the peak forecast for the 2012/2013 winter period.

Demand-Side Management

Demand Response is projected to be 1,882 MW, and Energy Efficiency is included in the Entities' Load Forecasts. These programs allow entities within the reporting area to have control over various amounts of load and capacity when needed for reliability purposes. Extreme real-time pricing response is considered as a capacity resource.

There is no significant change in the amount of Demand Response since last year, as Demand Response is projected to be 4.1 percent of Total Internal Demand, a 0.8 percentage point increase.

Generation

Utilities within the SERC-SE reporting area expect to have 66,296 MW of Existing-Certain, 2,412 MW of Existing-Other, and 0 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Oil/Gas/Dual Fuel are the primary sources of fuel within this area, contributing 45.2 percent of Existing-Certain resources. The secondary source of fuel is Coal representing 38.3 percent of Existing-Certain resources. In addition, 921 MW of Future-

Planned resources are expected to be added during the period. 76 MW of retirements, deferments, derates or other reductions will occur on the system during the month of December. There are no significant negative impacts to reliability anticipated for the winter period.

Approximately 974 MW of new generation has been added since the last winter season. There are neither new generator uprates in service nor any generation expected to be taken out of service during the period. A 110 MW unit has been on an extended forced outage and is expected to return to service by September 2012. Behind-the-meter generation is reported to be 0 MW. However, there are 115 MW of Other/Unknown resources anticipated for the period. Extended outages are not expected during this timeframe.

For the upcoming winter season, 67 MW of biomass, 4 MW of solar, and 4,936 MW of hydro/pumped storage are expected on-peak. Given that SERC does not collect the nameplate output of the units, no maximum capacity data is available. Only Firm capacity is counted toward the peak in Reserve Margin calculations. However, Future-Planned biomass generation 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.

Currently, entities are developing methods for incorporating variable resources into its planning processes. Variable resources are currently evaluated by analyzing their historical or projected output profiles. The result will be a determination of the comparative capacity value to that of a typical combustion turbine (CT) on the system.

Capacity Transactions

Utilities within the SERC-SE reporting area expect the net capacity transactions listed in summary table for the 2012/2013 winter season. These imports and exports have been included in the Reserve Margin calculations for the reporting area. All imports/exports were reported to be backed by Firm contracts for both generation and transmission, but none are associated with LDCs and only three (568.8 MWs) are considered “make whole.”

Reporting entities maintain emergency-reserve sharing agreements with organizations internal to the area and other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency MWs from these imports were not reported, but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet the demands of its load. Starting in January 2013, an additional wind power purchase of 202 MW will be available having Firm transmission.

Transmission

Currently, there are no concerns with meeting in-service dates for transmission improvements or specific projects needed to maintain reliability. Entities consistently evaluate the transmission system through operating studies and a model construction process. Additionally, there are no specific projects that were identified to maintain or enhance reliability.

Operations

Entities perform studies of operating conditions up to 13 months into the future. These studies are updated on a monthly basis and include the most current information regarding load forecasts, transmission and generation status, and Firm transmission commitments for the time period studied.

Regularly, entities in the area experience significant loop flows due to transactions external to the area. The availability of large amounts of excess generation within the Southeast reporting area results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on weather patterns, fuel costs, or market conditions outside the area. Significant changes in gas pricing dramatically impact dispatch patterns. All transmission constraints identified in current operational planning studies for the 2012/2013 winter season can be mitigated through generation adjustments, system reconfiguration, or system purchases. A large number of transmission and generator outages are necessary for the fall and winter seasons to maintain reliability and make system changes necessary to ensure compliance with new environmental regulations. Extensive coordination efforts are currently underway to manage scheduling challenges and avoid significant negative impacts to system reliability.

Hydroelectric units in the area are run in cooperation with the U.S. Army Corps of Engineers to maintain water levels and river flow. As a result of federal and state regulations, fossil generating units in the area have numerous operating limits related to air and water quality permit limits. A number of these units have unique limits on operations and emissions. Some are annual limits while others are seasonal, most particularly during the summer season. These restrictions have traditionally been continually managed in the daily operation of the system while maintaining reliability. New and more stringent environmental requirements pose a short-term challenge in making all the necessary system and plant modifications needed. [8.9]Overall, no environment restrictions or unusual conditions are projected to impact the reliability on the Bulk Electric System for the upcoming winter season.

Vulnerability Assessment

To address extended generator outages, extensive coordination efforts are currently underway to manage scheduling challenges and avoid capacity shortages due to any overlapping generation outages.

Individually, entities in the area continue to adjust internal planning studies and facility evaluations to address compliance issues regarding upcoming environmental regulations. Adverse reliability impacts from the regulations are not expected for the upcoming winter season.

The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak demand. Various companies within the SERC-SE reporting area 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 supply, established communication methods allow for additional supplies. These lines of communication include daily e-mails, phone calls, internet accessibility, SCADA, and instant messaging so that entities are well aware of fuels moving to various generating stations or to storage.

Some utilities have implemented fuel storage and coal conservation programs, as well as various fuel policies, to address concerns. Policies are also in place to ensure that fuel storages are filled well in advance of hurricane season (by June 1st of each year). These tactics help to ensure balance and create flexibility to serve anticipated generation needs. Vendor 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.

SERC-W

2012/2013 Winter Season: Assessment Area Summary

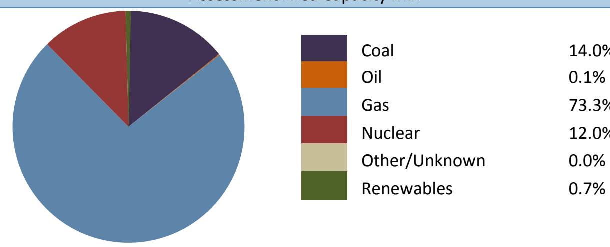
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**20,008**
Load-Modifying Demand Response	11
Net Internal Demand	**19,997**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	19,931
Actual Demand	19,868

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	-1,701
Existing-Certain and Future-Planned Capacity	35,894
Anticipated Resources	**34,193**
Anticipated Reserve Margin (%)	**70.99%**
Existing-Other and Future-Other Capacity	5,002
Prospective Resources	**39,195**
Prospective Reserve Margin (%)	**96.00%**
NERC Reference Margin Level (%)	**15.00%**

Assessment Area Footprint

Assessment Area Capacity Mix



Planning Reserve Margins

The Reporting area is projecting adequate Planning Reserve Margins during the winter period, given that none of the Planning Reserve Margins will fall below the NERC Reference Margin Level of 15 percent. Entities within this area do not adhere to any regional/reporting area targets or Reserve Margin criteria. Contributing factors to adequate margins are attributed to existing and owning resources, limited and long-term purchase contracts. Potential deactivations and anticipated unit outages are also factored into the plans to meet the target Reserve Margin when developing plans for the season.[88] There are no other anticipated reliability concerns for the 2012/2013 winter season.

Demand

The 2011/2012 winter actual demand was 19,277 MW and the peak demand forecast was projected to be 19,931 MW. Differences in the 2011/2012 winter actual and forecast are due to mild weather, while the forecast is based on normal weather. This year's 2012/2013 winter demand forecast is 20,176 MW. The expansion of industrial customers was a factor in an increased forecast, given that the projections resulted in fewer loads than originally expected. Forecast assumptions are unchanged for this year's forecast predictions. Energy requirements were expected to be nearly unchanged, due to the effect of slow economic recovery. Therefore the peak demand forecast does not reflect much growth. However, load growth remains high in the western portion of the area's Texas footprint where residential and commercial load growth is spurred by stronger economic growth. Specific industrial and commercial expansion projects are also driving load growth in service areas in the south Louisiana area.

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 11 MW and 0 MW, respectively. These programs are used to reduce peak demand on entity systems within the area. DSM programs among the utilities in the reporting area include: interruptible load programs for larger customers, direct-control load management programs for agricultural customers, and a range of conservation/load management programs for all customer segments.

Generation

Companies within the SERC-W reporting area expect to have 35,894 MW of Existing-Certain, 5,002 MW of Existing-Other, 1,074 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during the winter

[88] Individual entity criteria also help to establish resource adequacy by; allocations assigned as a member of the Southwest Power Pool (SPP) Reserve Sharing Group, Balancing Authority's (BAs) most severe single contingency, load forecast, and reserve requirement using historical allocations, and Loss-of Load expectation studies (0.1 day/year).

period. Oil/Gas/Dual Fuel units are the primary sources of fuel within this area, representing 66.2 percent of Existing-Certain resources. No Future-Planned resources are projected to be added during the period. Entities have reported 244 MW capacity reductions during the months of May through October 2012, and 421 MW of reductions during the upcoming winter. Significant negative impacts on capacity are not anticipated for the period.

Entities expect 178 MW of additional generation and uprates during the winter season. There are 421 MW of generation out of service during portions of the period. In addition, 411 MW will be brought back into service for the period. Behind-the-meter generation is reported to be 1,235 MW. Even though there are no ongoing long-term outages, entities have reported 141 MW of Other/Unknown resources in-service for the period.

Variable resources such as biomass, solar, and wind are not expected to be on peak during the season. However, 299 MW of hydro/pumped storage will contribute toward on-peak capacity. Only Firm capacity is counted toward the peak in calculations. In most cases, entities do not count variable resources due to its irregularity during peak demand periods. However, other entities consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest ten 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.

Capacity Transactions

Entities within the SERC-W reporting area expect the capacity transactions listed in the summary table for the 2012/2013 winter. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. All contracts are Firm agreements for both generation and transmission. All the capacity contracts are unit contingent with corresponding Firm transmission sourced from the facility.

Reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the demands of its load. Total emergency MWs from these imports were not reported, but are available as needed. In addition, there are no new import/export contracts available for 2012/2013 Winter Season.

Transmission

Entities within the reporting area are not expecting any delays in meeting in-service dates for projects scheduled for the winter assessment period. Additionally, there are no significant transmission facility outages that impact Bulk Electric System reliability. Prior to approval of any proposed maintenance outages, studies are completed to identify any impacts on reliability. No transmission issues have been identified that will impact reliability during the 2012/2013 winter season.

Operations

Companies within the SERC-W reporting area regularly participate in SERC NTSG seasonal reliability studies and in the ERAG MRO-RFC-SERC West-SPP (MRSWS) interregional studies. These studies test import capabilities into the area and are expected to predict increases/decreases for all transfer directions studied. Preliminary study results indicate that transfer capabilities for the upcoming winter season are expected to be at or near the test levels. Entities also do not expect any adverse operational impacts from capacity reductions of any kind during the upcoming winter period. The operational concerns for the area are the unseasonably cold temperatures that can occur, but there are well established processes and procedures for addressing these unusual circumstances.

Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system.

Vulnerability Assessment

Existing and owned resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources needed to meet the target Reserve Margin are considered when developing the one-year and 10-year resource plan. Loss-of-Load studies are also performed annually 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 16.85 percent Planning Reserve Margin. Currently, there are no concerns from long-term drought conditions, unit outages, Demand Response, variable generation, or other operational issues.

With the completion of the joint Acadiana Load Pocket Projects (Phase 1 was completed in 2011 and Phase 2 completed in 2012), the Acadiana area in south Louisiana experience no reliability issues in the winter of 2011 or the summer of 2012. These projects, which created a new 230 kV transmission overlay for the area, helps move power more effectively from the stronger sources on the northern boundary of the Acadiana Load Pocket and inject more directly into the underlying system further south. This new 230 kV overlay addressed the historical transmission congestion issues that have occurred in prior seasons and is expected to continue to help alleviate future congestion in the area. With these new facilities in place no reliability issues are expected in the Acadiana area for the upcoming 2012 Winter season.

Planned outages are normally scheduled outside of summer and winter peaking periods. The following factors are taken into account when compiling seasonal outage schedules: System Reserves, Load Pocket Reserves / Area Import Limits, Load Pocket Required Must Run criteria (Owned/Contracted), Co-owner Constraints, Winter Fuel Units (Firm Fuel Capability), Hurricane Season (Firm Fuel Capability), Contract Unit Outages, Diversified Scheduling of CCGT Units, Diversified Scheduling of Black Start Units, Outage Balance Between Spring and Fall Seasons, and Cost of Replacement Power. No operational concerns are expected for the season.

Fuel supply or delivery problems are not anticipated for the period. 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-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, 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 on some units. This was 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.

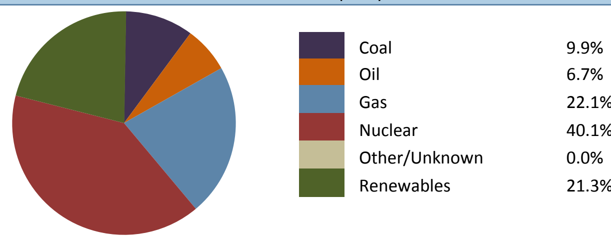
SPP

2012/2013 Winter Season: Assessment Area Summary

2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**35,810**
Load-Modifying Demand Response	732
Net Internal Demand	**35,079**
2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	41,089
Actual Demand	35,810
2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	200
Net Capacity Transactions (Firm and Expected)	-371
Existing-Certain and Future-Planned Capacity	80,508
Anticipated Resources	**80,337**
Anticipated Reserve Margin (%)	**129.02%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**80,337**
Prospective Reserve Margin (%)	**129.02%**
NERC Reference Margin Level (%)	**13.60%**

Assessment Area Footprint

Assessment Area Capacity Mix



Planning Reserve Margins

SPP Criteria requires members to maintain a minimum capacity margin of 12 percent which translates to a 13.6 percent Reserve Margin. SPP RTO is projected to have adequate Planning Reserve Margins for the assessment period as all of the planning reserve margins are well above the 13.6 percent reference reserve margin. This level of adequacy is supported by the SPP RTO's available generation fleet and the projected demand decrease projected for the winter timeframe.

The SPP RTO footprint is subject to extreme winter weather conditions that can impact demand and generation supply as evidenced in February 2011. Those conditions caused generation supply problems for a few members but did not negatively impact reliability for the broader SPP RTO assessment area. The region is even better prepared should extreme weather occur again this winter.

With the Federal Circuit Court's decision to vacate the Cross-State Air Pollution Rule (CSAPR), this regulation is not expected to impact the SPP RTO during the winter assessment period. The Environmental Protection Agency's (EPA) Mercury Air Toxic Standard (MATS) regulation will impact the SPP RTO region when it become effective, but it is not anticipated to cause reliability concerns for the 2012/2013 winter as discussed later in this assessment.

Demand

The projected non-coincident Total Internal Demand forecast for the 2011/2012 winter peak was 41,089 MW. The projected coincident 2012/2013 Total Internal Demand winter peak forecast is 35,810 MW. The actual 2011/2012 winter peak demand was 35,281 MW. The projected coincident forecast beginning with the 2012/2013 winter assessment uses modeling data submitted by the individual entities. In previous years SPP RTO has reported a non-coincident Total Internal Demand forecast based on aggregated member data. The increase in Estimated Diversity from the 2011-2012 winter assessment to the 2012/2013 winter assessment is due to SPP RTO performing the calculation instead of the individual balancing authorities. The ratio of actual peak coincident load to the modeled peak non-coincident load from the winter 2011-2012 was used to obtain the forecasted peak demand from the 2012/2013 winter model non-coincidental peak.

Demand-Side Management

Demand response programs in the SPP RTO footprint are voluntary and are primarily targeted for summer peak load reduction use. SPP RTO members include their own Demand Response and energy efficiency programs as reductions in their load forecasts. 726 MW of interruptible and non-controllable demand and 178 MW of direct control load management will be available for use in reducing winter peak load. SPP RTO members report 235 MW of energy efficiency programs for the assessment period.

Generation

For the 2012/2013 winter assessment period, SPP RTO forecasts 78,631 MW of Existing- Certain; 0 MW of Existing-Other; and 0 MW of Existing-Inoperable Resources. The primary fuel sources in the SPP RTO footprint are gas (45 percent) and coal (37 percent). The higher Existing-Certain forecast, compared to previous assessments, is due to a change in the way SPP is reporting capacity resources. In the past, SPP RTO sent the assessments to the SPP Members and had them report their Expected-Certain resources. SPP RTO is now using the SPP Model Development Working Group model as a base case for all current year capacity resources, and will then subtract out all the reported outages. The use of the MDWG data set provides a consistent source of data for load, generation, and transmission topology for use in the NERC reliability assessments and SPP's transmission planning studies.

SPP RTO projects 597 MW of Future-Planned coal and 1,280 MW of Future-Planned wind resources to be added during the 2012/2013 winter of which 684 MW will be expected on peak. No upgrades or uprates are expected.

SPP RTO has added a total nameplate of 2,318 MW new wind generation, of which 70 MW is expected on peak, since the 2012 summer reporting season as shown below:

- 1,067 MWs of wind generation added in June
- 1,251 MWs of wind generation added in August

SPP RTO projects no capacity reductions to occur during the 2012/2013 winter season.

Because of the significant reserve margins in the SPP RTO assessment area for the 2012/2013 winter season, the capacity additions noted above are not expected to cause any short-term impacts.

For the 2012/2013 winter season SPP RTO projects less than 7 percent, based on historical data, of the total wind capacity of 6,992 MWs to be available on peak. Even though there has been a significant drought in the SPP region, no hydro capacity and conventional thermal unit reductions are expected during this season. The on-peak capacity values for variable resources are based on the 2011/2012 actual output percentages at winter peak.

Capacity Transactions

SPP RTO members, along with some members of the SERC Region, participate in a Reserve Sharing Group. Group members receive contingency reserve assistance from each other; however, due to the high reserve margin in the SPP RTO footprint, group participants within SPP generally transfer reserves into the SERC Region. Therefore, the group does not require support from generation resources located outside the SPP RTO Region.

Operations

As noted earlier in the assessment, two EPA regulations, the CSAPR and MATS, were expected to impact generation in the SPP RTO footprint. However, the CSAPR has been vacated and due to the timing of the MATS regulation, SPP RTO does not anticipate operational concerns for the upcoming winter season.

SPP RTO is currently working to implement a consolidated Balancing Authority within its footprint with centralized unit commitment as well as a day ahead energy market including ancillary services. This is expected to be in operation in early 2014. The centralized commitment and balancing activities are expected to ease the integration of a larger amount of variable generation. SPP RTO has implemented a centralized forecasting service for wind generation and is working with members to determine responsibility for provision of additional meteorological data in order to improve that forecast.

Vulnerability Assessment

Long-term (> 6 months) drought conditions exist across many areas of the SPP RTO footprint. However, the affected areas have minimal hydro facilities and unit derates have not occurred due to low cooling water or supply water levels. Since heavy winter and spring rain totals tend to relieve the drought conditions, resource adequacy or operational concerns are not anticipated due to drought conditions for the upcoming winter.

Since SPP RTO has an abundant generation supply, significant long-term generator outages are not a potential concern. There are no short-term concerns about Demand Response programs being unresponsive or unavailable as SPP RTO exceeds its minimum reserve margin requirements even without relying on these programs.

To ensure the most efficient and effective use of renewable resources, SPP's operations staff must maintain and enhance its ability to project how much wind generation will be available to reliably serve load over given time periods. Unpredictability remains the largest obstacle in effectively integrating wind energy into SPP's generating mix. As wind speeds change, utilities must instantaneously switch to and from other generating resources to compensate for this variability. Increasing the capability to forecast wind's time, location, and speed will significantly enhance operators' ability to reliably manage the grid. In 2011, SPP implemented a new wind forecasting tool to generate five-minute, hourly, and day-ahead projections.

The Acadiana Load Pocket located in southern Louisiana did not experience any reliability issues in the winter of 2011 or the summer of 2012. The addition of Cleco's 230 kV line from Roark to Sellers Road and Entergy's Sellers Road to Meaux 230 kV line prior to the summer of 2011, along with the energizing of the Segura 230 kV line in fall 2011, alleviated a portion of the most limiting elements. The 230 kV line from Labbe to Bonin was energized in February 2012, and two other 230 kV lines from Wells to Labbe and Labbe to Sellers Rd. were energized on June 28, 2012. The completion of these projects should further alleviate transmission congestion in this area and the planned Acadiana Load Pocket projects have been completed.

SPP RTO conducted a reliability assessment based on members' plans for compliance with the CSAPR and MATS in April 2012. As noted above, SPP RTO does not anticipate that either of these EPA regulations will have a reliability impact in the SPP RTO area during the 2012/2013 winter assessment period. SPP Staff are currently reviewing outage requests submitted through 2016 to determine if a large number of outages or retirements will cause any reliability concerns. The results of that study are expected this year.[89]

SPP RTO reviews potential fuel supply limitations by consulting with its generation-owning and generation-controlling members via electronic communications. There are no known infrastructure issues which should impact fuel deliverability, as the SPP Region is blanketed by major pipelines and railroads that provide access to an adequate fuel supply. SPP Criteria require coal and natural gas-fired power plants, which make up approximately 37 percent and 45 percent of total generation respectively, to maintain sufficient quantities of standby fuel on site in case of deliverability issues.[90]

[89] Results in October are preliminary.
[90] SPP Criteria 2.4.2

WECC

2012/2013 Winter Season: Assessment Area Summary

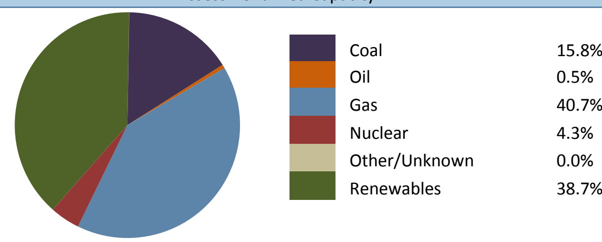
2012/2013 Winter Peak Demand Projections	MW
Total Internal Demand	**131,070**
Load-Modifying Demand Response	1,920
Net Internal Demand	**129,150**

2011/2012 Winter Comparison	MW
Total Internal Demand Forecast	129,485
Actual Demand	126,337

Assessment Area Footprint

2012/2013 Resources and Reserve Margins	
Resource-Side Demand Response	0
Net Capacity Transactions (Firm and Expected)	0
Existing-Certain and Future-Planned Capacity	182,551
Anticipated Resources	**182,551**
Anticipated Reserve Margin (%)	**41.35%**
Existing-Other and Future-Other Capacity	0
Prospective Resources	**182,551**
Prospective Reserve Margin (%)	**41.35%**
NERC Reference Margin Level (%)	**14.60%**

Assessment Area Capacity Mix



Subregional Considerations

The WECC Assessment Area is divided into four subregions for NERC's seasonal assessments: 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, the subregions are structured around Reserve Sharing Groups. These groups have similar demand patterns and have similar operating practices. Second, the WECC Reliability Coordinator (RC) collects actual demand data from the Reserve Sharing groups. Creating the seasonal assessments using the same footprint allows for after-the-fact comparison between demand forecasts and actual demand.

Planning Reserve Margins

Reserve Margins for the summer peaking WECC Assessment Area are projected to remain above the NERC Reference Reserve Margin Level during the winter season. Alberta, Canada has the lowest projected Anticipated Capacity Resources (ACR) reserve margin for the upcoming winter, at 12.2 percent. However, that ACR exceeds the Reference Reserve Margin of 11.7 percent and is roughly double the operating reserve requirement.

The reserve margin adequacy is largely due to the construction of power plants in anticipation of a load growth that was interrupted by the recent recession and slow economic recovery. It should be noted that abnormal weather conditions would result in different reserve margins and severe adverse weather conditions or unexpected equipment failure could result in localized power supply or delivery limitations.

Demand

The aggregate WECC 2012/2013 winter total coincident peak demand is forecast to be 131,070 MW and is projected to occur in December. The forecast is 3.7 percent above last winter's actual peak demand of 126,337 MW, which was established under generally normal to slightly-warmer-than-normal temperatures with poor economic conditions in the region. The 2012/2013 winter coincident peak demand forecast is 1.2 percent above last winter's forecast coincident peak demand of 129,485 MW. The nominal increase in the prior year to current year winter peak demand forecasts largely reflects an expectation of nominal economic growth.

Demand-Side Management

Demand-side management programs are designed to reduce peak demands and conserve energy. These programs incorporate both active and passive actions. Passive programs generally focus on activities that reduce annual energy consumption while simultaneously reducing peak demand. Entities within WECC have reported peak demand reductions associated with such programs at 393 MW.

Active DSM programs offered by Load-Serving Entities (LSE) vary widely. The 2012/2013 winter demand forecast includes 79 MW of Direct Control Load Management (DCLM), 1,427 MW of contractually interruptible demand, zero MW of critical-peak-pricing with control, and 414 MW of load as a capacity resource. As a percent of Total Internal Demand, total demand response could reduce peak demand by 1.5 percent. DCLM programs largely focus on air conditioner cycling programs while interruptible demand programs focus primarily on large water pumping operations and large industrial operations such as mining.

State and other regulatory drivers have led to nominal increases in DSM program penetration within the WECC subregions and, within some established market structures, DSM has been established as an ancillary service.

Generation

WECC's Western Interconnection modeling data report the available Existing-Certain capacity at 181,245 MW, Existing-Other capacity at zero megawatts, and Existing-Inoperable capability at 6,051 MW. The modeled Existing-Certain capabilities by fuel type are:

- 28.8 percent hydroelectric;
- 16.6 percent coal;
- 40.6 percent natural gas;
- 4.3 percent nuclear; and
- 9.7 percent all other fuel types.

It is expected that coal and natural gas will be readily available throughout the winter period. As is normally the case, hydroelectric generation may be somewhat limited but this limitation is adequately reflected in the reported hydro derates. Capacity changes since year-end 2011 are classified as Future-Planned. The net Future-Planned capacity changes total 2,917 MW from the start of the year through the end of September.

Capacity additions from the end of September through the end of the winter period are also classified as Future-Planned. Those capacity changes total 1,787 MW.

WECC's modeling for the winter assessment peak period gives a total renewables expected capacity of 60,497 MW from a nameplate capacity of 81,727 MW.[91]

Capacity Transactions

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins, nor does WECC rely on outside assistance or external resources for emergency imports, and does not model exports to areas outside of WECC.

Transmission

No project delays or temporary service outages of transmission facilities have been reported that will adversely impact reliability during the 2012/2013 winter season. In addition, no specific projects have been reported that are needed to maintain reliability.

Operations

WECC staff does not perform any special operating studies concerning extreme weather or drought conditions for the seasonal assessments. However, these studies are performed by the individual LSEs and BAs within WECC.

[91] The renewable expected capacity modeling for wind resources uses generation curves created from three years of one-hour interval wind speed data. Expected capacity modeling for solar resources uses generation curves created from two years of insolation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capacities are based on nominal plant ratings.

The highly variable nature of wind and solar resources complicates daily power grid operation, often more significantly during off-peak periods than during on-peak periods. Operational procedures, such as implementing and testing resource curtailment capability and increased reserve requirements, are expected to address the wind and solar generation variability issues.

A significant portion of the demand response is related to seasonally-impacted loads such as residential air conditioning and irrigation system pumps. Hence, available demand response is less during the winter season than during the summer season. Due to the reduced winter season demand and increased margins, in most areas compared to the summer season, demand response dependability is of little concern.

Power plants operate under numerous environmental and other regulatory restrictions, including emission, water level, and water temperature limitations. The cumulative magnitude of the restrictions, although not quantified, is incorporated into the expected on-peak capabilities used for this assessment and the restrictions are not expected to adversely affect reliability during the winter season.

Vulnerability Assessment

The west experienced a relatively warm and dry summer, resulting in reservoir draw downs in some areas. The Colorado River basin is in essentially the twelfth year of a persistent drought.[92] It is expected that the reduced river flows will result in increased thermal-based energy generation but will not significantly affect the ability to meet peak demand. The margin information presented in this assessment reflects an assumed adverse hydroelectric generation condition.

The CISO has reported a San Francisco Bay area Special Protection System (SPS) as a temporary solution to a current local area congestion issue. Also, the CISO has reported three SPSs that are temporary bulk power transmission facility solutions related to new variable resource additions.

WECC entities have not reported any pending environmental regulations that have an impact on their upcoming season planning and have not included potential environmental regulation effects in their upcoming season plans.

Area entities report that they routinely coordinate their fuel supply needs with fuel and transportation suppliers on several levels. For example, significant portions of the coal supply are acquired under long-term contracts with mines and transportation providers and the power plants generally have significant on-site coal storage facilities. These long-term arrangements are largely unaffected by short-term conditions so seasonal planning coordination beyond pre-established parameters is minimal.

On the other hand, natural gas deliveries are often scheduled on a very short-term basis, e.g. daily. This short-term acquisition process, coupled with generally very limited storage located near power plants and gas pipeline pressure limitations, may lead to supply interruptions should other conditions, such as an unexpected cold snap or colder-than-expected temperatures occur. These temperature-driven supply interruption events are generally localized and are not expected to significantly affect reliability this winter.

[92] Upper Colorado River Basin Region: http://www.drought.gov/drought/regional-programs/ucrb/ucrb-home

Appendix I: Estimated 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**: 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 in seasonal assessments:

Existing Capacity Resources

- **Existing-Certain**: Existing generation resources available to operate and deliver power within or into the assessment area (or Region) during the period of assessment.
- **Existing-Other**: Existing generation resources that may be available to operate and deliver power within or into the assessment area (or Region) during the period of assessment, but may be curtailed or interrupted at any time for various reasons.
- **Existing, but Inoperable**: Existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period assessment.

Existing Capacity Resources

- **Future-Planned**: Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of assessment.
- **Future-Other**: Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

Capacity Transactions

- Net Firm and Expected Transactions: Firm and Expected Imports, minus Firm and Expected Exports; including all Firm contracts with a reasonable expectation to be implemented.

Reserve Margins

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.

Planning Reserve Margins for each assessment area are compared to the NERC Reference Margin Level, which is assigned for each NERC assessment area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Reserve Margin, NERC has applied a 10 or 15 percent Reference Reserve Margin for predominately hydro or thermal systems, respectively.

The NERC Reference Reserve Margin Level serves as a basis for determining whether more resources (*e.g.,* generation, Demand-Side Management, transfers) may be needed within that Region/subregion.

Note 1: Demand and Supply forecasts were reported between February and August, 2011—depending on the assessment area.

Note 2: Values for both Total Internal Demand and Net Internal Demand for each assessment area represent on-peak projections.

Note 3: The WECC-US peak demands or resources do not necessarily equal the sums of the non-coincident WECC-US subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S., Canada, and México peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

Appendix II: Abbreviations Used in this Report

Abbreviation	Term	Abbreviation	Term
A/C	Air Conditioning	IA	Interchange Authority
AEP	American Electric Power	ICAP	Installed Capacity
AFC	Available Flowgate Capability	ICR	Installed Capacity Requirement
ASM	Ancillary Services Market	IESO	Independent Electric System Operator (in Ontario)
ATCLLC	American Transmission Company	IOU	Investor Owned Utility
ATR	AREA Transmission Review (of NYISO)	IPSI	Integrated Power System Plan
AWEA	American Wind Energy Association	IRM	Installed Reserve Margin
BA	Balancing Authorities	IROL	Interconnection Reliability Operating Limit
BASN	Basin (subregion of WECC)	IRP	Integrated Resource Plan
BCF	Billion cubic feet	ISO	Independent System Operator
BCF/d	Billion cubic feet per day	ISO-NE	New England Independent System Operator
CALN	California-North (subregion of WECC)	kV	Kilovolts (one thousand volts)
CALS	California-South (subregion of WECC)	LaaRs	Loads acting as a Resource
CANW	WECC-Canada (subregion of WECC)	LCR	Locational Installed Capacity Requirements
CFL	Compact Fluorescent Light	LDC	Liquidated Damage Contract
CMPA	California-Mexico Power Area	LFU	Load Forecast Uncertainty
COI	California-Oregon Intertie	LNG	Liquefied Natural Gas
COS	Coordinated Outage (transmission) System	LOLE	Loss of Load Expectation
CPUC	California Public Utilities Commission	LOLP	Loss Of Load Probability
CRO	Contingency Reserve Obligation	LOOP	Loss of off-site power
CRPP	Comprehensive Reliability Planning Process (of NYISO)	LRP	Long Range Plan
DADRP	Day-Ahead Demand Response Program	LSE	Load-serving Entities
dc	Direct Current	LTRA	Long-Term Reliability Assessment
DCLM	Direct Controlled Load Management	LTSG	Long-term Study Group
DFW	Dallas/Fort Worth	MAAC	Mid-Atlantic Area Council
DLC	Direct Load Control	Maf	Million acre-feet
DOE	U.S. Department of Energy	MAIN	Mid-America Interconnected Network, Inc.
DSG	Dynamics Study Group	MAPP	Mid-Continent Area Power Pool
DSI	Direct-served Industry	MCRSG	Midwest Contingency Reserve Sharing Group
DSM	Demand-Side Management	MEXW	WECC-Mexico (subregion of WECC)
DSW	Desert Southwest (subregion of WECC)	MISO	Midwest Independent Transmission System Operator
DVAR	D-VAR® reactive power compensation system	MPRP	Maine Power Reliability Program
EDRP	Emergency Demand Response Program	MRO	Midwest Reliability Organization
EE	Energy Efficiency	MVA	MegaVolt Ampere
EEA	Energy Emergency Alert	MVAr	MegaVolt Ampere reactive
EECP	Emergency Electric Curtailment Plan	MW	Megawatts (millions of watts)
EIA	Energy Information Agency (U.S. Department of Energy)	MWEX	Minnesota Wisconsin Export
EILS	Emergency Interruptible Load Service (of ERCOT)	NB	New Brunswick
EISA	Energy Independence and Security Act of 2007 (USA)	NBSO	New Brunswick System Operator
ELCC	Effective Load-carrying Capability	NDEX	North Dakota Export Stability Interface
EMTP	Electromagnetic Transient Program	NEEWS	New England East West Solution
ENS	Energy Not Served	NERC	North American Electric Reliability Corporation
EOP	Emergency Operating Procedure	NIETC	National Interest Electric Transmission Corridor
ERAG	Eastern Interconnection Reliability Assessment Group	NOPSG	Northwest Operation and Planning Study Group
ERCOT	Electric Reliability Council of Texas	NORW	Northwest (subregion of WECC)
ERO	Electric Reliability Organization	NPCC	Northeast Power Coordinating Council
FCITC	First Contingency Incremental Transfer Capability	NPDES	National Pollutant Discharge Elimination System
FCM	Forward Capacity Market	NPPD	Nebraska Public Power District
FERC	U.S. Federal Energy Regulatory Commission	NSPI	Nova Scotia Power Inc.
FP	*Future-Planned*	NTSG	Near-term Study Group
FO	*Future-Other*	NWPP	Northwest Power Pool Area (subregion of WECC)
FRCC	Florida Reliability Coordinating Council	NYISO	New York Independent System Operator
GADS	Generating Availability Data System	NYPA	New York Planning Authority
GDP	Gross Domestic Product	NYRSC	New York State Reliability Council, LLC
GGGS	Gerald Gentleman Station Stability	OASIS	Open Access Same Time Information Service
GHG	Greenhouse Gas	OATT	Open Access Transmission Tariff
GRSP	Generation Reserve Sharing Pool (of MAPP)	OP	Operating Procedure
GTA	Greater Toronto Area	OPA	Ontario Power Authority
GWh	Gigawatt hours	OPPD	Omaha Public Power District
HDD	Heating Degree Days	ORWG	Operating Reliability Working Group
HVac	Heating, Ventilating, and Air Conditioning	OTC	Operating Transfer Capability

Abbreviation	Term	Abbreviation	Term
OVEC	Ohio Valley Electric Corporation	SCD	Security Constrained Dispatch
PA	Planning Authority	SCDWG	Short Circuit Database Working Group
PACE	PacifiCorp East	SCEC	State Capacity Emergency Coordinator (of FRCC)
PAR	Phase Angle Regulators	SCR	Special Case Resources
PC	NERC Planning Committee	SEMA	Southeastern Massachusetts
PCAP	Pre-Contingency Action Plans	SEPA	State Environmental Protection Administration
PCC	Planning Coordination Committee (of WECC)	SERC	SERC Reliability Corporation
PJM	PJM Interconnection	SMUD	Sacramento Municipal Utility District
PRB	Powder River Basin	SOL	System Operating Limits
PRC	Public Regulation Commission	SPP	Southwest Power Pool
PRSG	Planned Reserve Sharing Group	SPS	Special Protection System
PSA	Power Supply Assessment	SPS	Special Protection Schemes
PUCN	Public Utilities Commission of Nevada	SRIS	System Reliability Impact Studies
QSE	Qualified Scheduling Entities	SRWG	System Review Working Group
RA	Resource Adequacy	STATCOM	Static Synchronous Compensator
RAP	Remedial Action Plan	STEP	SPP Transmission Expansion Plan
RAR	Resource Adequacy Requirement	SVC	Static VAr Compensation
RAS	Reliability Assessment Subcommittee	TCF	Trillion Cubic Feet
RC	Reliability Coordinator	TFCP	Task Force on Coordination of Planning
RCC	Reliability Coordinating Committee	THI	Temperature Humidity Index
RFC	ReliabilityFirst Corporation	TIC	Total Import Capability
RFP	Request For Proposal	TID	Total Internal Demand
RGGI	Regional Greenhouse Gas Initiative	TLR	Transmission Loading Relief
RIS	Resource Issues Subcommittee	TOP	Transmission Operator
RMR	Reliability Must Run	TPL	Transmission Planning
RMRG	Rocky Mountain Reserve Group	TRE	Texas Regional Entity
ROCK	Rockies (subregion of WECC)	TRM	Transmission Reliability Margins
RP	Reliability Planner	TS	Transformer Station
RPM	Reliability Pricing Mode	TSP	Transmission Service Provider
RRS	Reliability Review Subcommittee	TSS	Technical Studies Subcommittee
RSG	Reserve Sharing Group	TVA	Tennessee Valley Authority
RTEP	Regional Transmission Expansion Plan (for PJM)	UFLS	Under Frequency Load Shedding Schemes
RTO	Regional Transmission Organization	UVLS	Under Voltage Load-Shedding
RTP	Real-time Pricing	VAr	Voltampere reactive
RTWG	Renewable Technologies Working Group	VACAR	Virginia and Carolinas (subregion of SERC)
SA	Security Analysis	VSAT	Voltage Stability Assessment Tool
SasKPower	Saskatchewan Power Corp.	WALC	Western Area Lower Colorado
SCADA	Supervisory Control and Data Acquisition	WECC	Western Electricity Coordinating Council
SCC	Seasonal Claimed Capability	WTHI	Weighted Temperature-Humidity Index
		WUMS	Wisconsin-Upper Michigan Systems

Appendix III: Reliability Assessment Subcommittee Roster

Reliability Assessment Subcommittee Members

Name	Position	Represents	Job Title	Organization
Vince Ordax	Chair	FRCC*	Manager of Planning	FRCC
Curtis Crews	Vice Chair	TRE*	Lead Reliability Assessment Engineer	TRE
Justin Michlig	Member	MRO	Transmission Planning Specialty Engineer	Xcel
William B. Kunkel	Member	MRO*	Senior Engineer	MRO
John Lawhorn	Member	MRO	Senior Director, Regulatory and Economic Studies	Midwest ISO, Inc.
Madhuri Kandukuri	Member	MRO	Senior Engineer , Regulatory and Economic Studies	Midwest ISO, Inc.
Josh Collins	Member	MRO	Engineer I	Midwest ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
Salva R. Andiappan	Member	MRO	Manager- Modeling and Reliability Assessments	MRO
Rao Konidena	Member	MRO	Manager, Resource Forecasting	Midwest ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
Philip A. Fedora	Member	NPCC*	Assistant Vice President, Reliability Services	NPCC
John G Mosier Jr.	Member	NPCC*	Assistant Vice President of System Operations	NPCC
Paul A. Roman	Member	NPCC	Manager, Operations Planning	NPCC
Peter Wong	Member	NPCC	Manager, Resource Adequacy	ISO-NE
Joaquin (Jack) M. Alvarez	Member	NPCC	Senior Engineer	NPCC
Kevan L. Jefferies	Member	NPCC	Manager - Market Forecasts and Modeling	Ontario Power Generation Inc.
Paul D. Kure	Member	RFC*	Senior Consultant, Resources	RFC
Tim Fryfogle	Member	RFC*	Associate Engineer	RFC
Mark J.Kuras	Member	RFC	Senior Lead Engineer	PJM
Bob Mariotti	Member	RFC	Supervisor - Short Term Forecasting	DTE Energy
Glenn P Catenacci	Member	RFC	Principal Staff Engineer	PSE&G
Esam A.F. Khadr	Member	RFC	Director Electric Delivery Planning	PSE&G
Mohammed Ahmed	Member	RFC	Manager, East Training Planning	AEP
Barbara A. Doland	Member	SERC*	Data Analyst	SERC
Maria Haney	Member	SERC*	Reliability Assessment Engineer	SERC
Hubert C. Young	Member	SERC	Senior Manager, Capacity Planning	TVA
K. R. Chakravarthi	Member	SERC	Manager, Interconnection and Special Studies	Southern Company Services, Inc.
Gary S. Brinkworth	Member	SERC	Senior Manager	TVA
Alan C. Wahlstrom	Member	SPP RE*	Lead Engineer, Event Analysis & Reliability Assessments	SPP RE
David Kelley	Member	SPP RE*	Manager, Interregional Coordination	SPP Inc.
Deborah K. Currie	Member	SPP RE*	Lead Engineer	SPP RE
James Useldinger	Member	SPP RE	Manager, T&D System Operations	KCP&L
Warren Lasher	Member	TRE	Manager, System Assessment	ERCOT
Layne Brown	Member	WECC*	Manager, Reliability Assessments	WECC
Tina G. Ko	Member	WECC	Manager, Resources & Loads Analysis	BPA
James Leigh-Kendall	Member	WECC	Manager, Reliability Compliance and Coordination	SMUD
Jerry D. Rust	Observer	N/A	President	NPPC
Sedina Eric	Observer	GOV	Electrical Engineer	FERC
David J. Burnham	Observer	GOV	Electrical Engineer	FERC
Patricia Hoffman	Observer	GOV	Assistant Secretary	DOE
Maria A. Hanley	Observer	GOV	Energy Analyst	DOE-NETL
Erik Paul Shuster	Observer	GOV	Engineer	DOE
Peter Balash	Observer	GOV	Senior Economist	DOE
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