

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

200- #&\$%\$ Dcgh K]bhYf Reliability Assessment



to ensure
the reliability of the
bulk power system

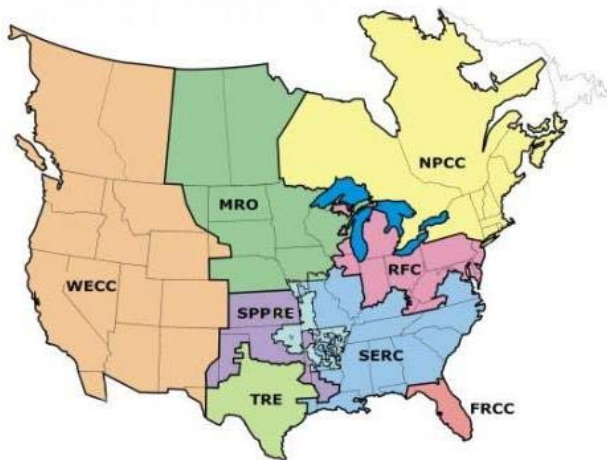
Bcj Ya VYf 2010

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses reliability annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization in North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.¹

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight Regional Areas as shown on the map below (see Table A). The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



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

Table A: NERC Regional Entities

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

¹ 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 BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro, making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards setting bodies by the *Régie de l’énergie* of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have a framework in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

NERC’s Mission	i
Post-Winter Reliability Assessment Summary	1
Lessons Learned	1
Demand	2
Operations	4
Reliability Coordinator Assessment Highlights	6
ERCOT Reliability Coordinator	8
FRCC Reliability Coordinator	10
New England Reliability Coordinator	13
NBSO Reliability Coordinator	18
Midwest ISO Reliability Coordinator	20
New York Reliability Coordinator	22
PJM RTO Reliability Coordinator	24
IESO Reliability Coordinator	25
Québec Reliability Coordinator	26
SaskPower Reliability Coordinator	30
SERC Reliability Coordinators	32
SPP Reliability Coordinator	35
WECC Reliability Coordinator	38
About This Report	42
References	43
RAS Roster	44

Post-Winter Reliability Assessment Summary

Bulk power system reliability was maintained during the 2009/2010 winter season.² While the winter season did present some unusual operating conditions in the southeastern part of the United States due to colder than normal temperatures, sufficient reserves and operational reliability were sustained.

Lessons Learned

Short-term Operational Strategies to Manage Extreme Weather Conditions

As observed in much of the southeast, including Texas, Florida, and southern SERC subregions, meeting peak demands in the winter can pose significant operational challenges. For these areas, higher than expected peak demands were experienced when compared to their seasonal forecast.

The FRCC has taken proactive measures to ensure reliability through extreme weather events as a result of the conditions experienced during the 2009/2010 Winter season. The FRCC Operating Reliability Subcommittee (ORS) plans to draft a check sheet for future capacity advisories and alerts. The check sheet will cover items to be reviewed during the pre-event conference calls such as review operation on liquid fuel, ensure permitting is adequate, awareness of demineralized water constraints and any other environmental constraints which may impact resource dispatch.

Because of the weather uncertainty associated with a seasonal forecast, which is developed months in advance of the actual peak, short-term operational strategies must be relied on to mitigate potential reliability situations. The ability to update system models to reflect future operating conditions, such as updating of appropriate facility ratings and adjusting for changes in merit-order to account for environmental constraints that affect resource dispatch, is a key operational strategy to prepare for unexpected high demand and ensure resources are available to deliver power when needed. Enhancements to system models within FRCC should improve the Region's ability to gain more certainty in the day-ahead forecast.

Monitoring Wind Output

As wind resources increase across North America, the real-time monitoring of these resources has become increasingly important to manage the overall resource portfolio. Forecasting the output of variable generation is critical to bulk power system reliability to ensure that adequate resources are available for ancillary services and ramping requirements. In the case of wind power, forecasting is one of the key tools needed to increase the operator's awareness of wind plant output and assist in managing its uncertainty.³

In Saskatchewan, the importance of planning each hour of the day, in particular the next hour, to ensure that there is enough capacity to meet any peak loads was demonstrated during the 2009/2010 winter peak. Wind capacity was an important contributor to meeting the peak load providing 85 percent of nameplate capacity. Forecasting the amount of wind production during the next hour is critical for operators to make the proper selection of units to commit. Without proper forecasts and tools, system operators will be required to maintain additional upward and downward flexibility on an ongoing basis.

² The winter season is December 2009 through February 2010

³ NERC IVGTF Report: Variable Generation Power Forecasting for Operators

<http://www.nerc.com/files/Variab%20Generationn%20Power%20Forecasting%20for%20Operations.pdf>

Demand

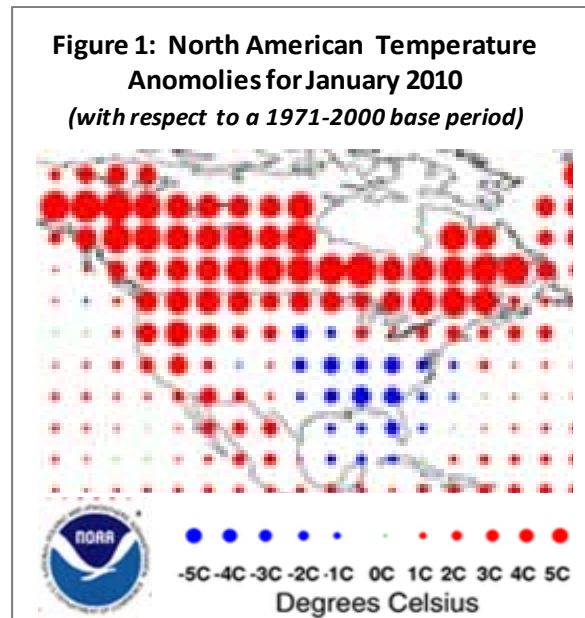
Annual peak demands were experienced during the 2009/2010 winter season for a majority of the Canadian subregions, which is primarily due to electric heating in the residential sector. For the 2009/2010 winter season, temperatures were warmer than normal when compared to historical averages (Figure 1). While some cold-snaps did occur, no reliability issues were experienced. Normal operating procedures maintained reliability throughout the winter season and peak demand was met as expected.

Warmer than normal weather conditions were observed in Canada during the study period. In these subregions, actual peak demand was below forecast levels and, therefore, there were no resource constraints or concerns in meeting the peak. MRO-Saskatchewan reached their all-time record high of 3,231 MW, which was realized after a week-long cold snap on December 14, 2009. Firm demand was not interrupted in any of the winter-peaking subregions, though, in some instances Demand Response was called to respond to market conditions— in these situations, Demand Response performed as expected.

For the 2009/2010 winter season, maintaining reliability was more challenging in the southeastern part of the United States than in Canada. That said, resource adequacy was not a concern in the United States during the winter. Further, Planning Reserve Margins were forecast to be high due to the economic recession impacting projected peak demand.

During the early to mid-part of January 2010, a period of prolonged and extreme cold weather was experienced in the south-eastern part of the United States. The cold-weather snap primarily targeted the TRE and FRCC regions as well as the southern SERC subregions (Delta, Southeastern, and VACAR). In these areas, average temperatures were the coldest since 2000.⁴ While extreme weather events are considered during the planning process (often referred to as a 90/10 forecast), in many cases the actual realized demand was beyond the 90/10 forecast. Furthermore, despite the economic recession effects which were planned to significantly reduce the demand for electricity (as much as four percent when compared to the prior winter), the unusually cold weather led to all-time record or near all-time record winter peak demand in these areas due to the electric heating demands in those areas.

In TRE, the day-ahead forecast for the peak day was equal to approximately 130 percent of the seasonal forecast (see Figure 2). In addition, high demands were realized throughout the winter season, exceeding the seasonal forecast several times. Nevertheless, day-ahead preparations minimized potential reliability concerns by committing the resources needed to meet peak demand. While Demand Response was not used to meet peak demand, a 922 MW reduction was realized (101 percent



⁴ International Weather Trends: <http://blog.compweather.com/2010/02/january-2010-retail-business-weather-round-up/>

of the committed Demand Response capacity) when the LaaR⁵ program was deployed for operating reserves following a transformer outage at a nuclear plant one day after the peak demand.

In FRCC, the cold-snap led to a day-ahead forecast equal to approximately 110 percent of the seasonal forecast (Figure 3). The prolonged nature of this event resulted in operational challenges that stressed the Region’s system. Similar conditions were also experienced in SERC-Delta and SERC-Southeastern (see Figure 4 and 5).

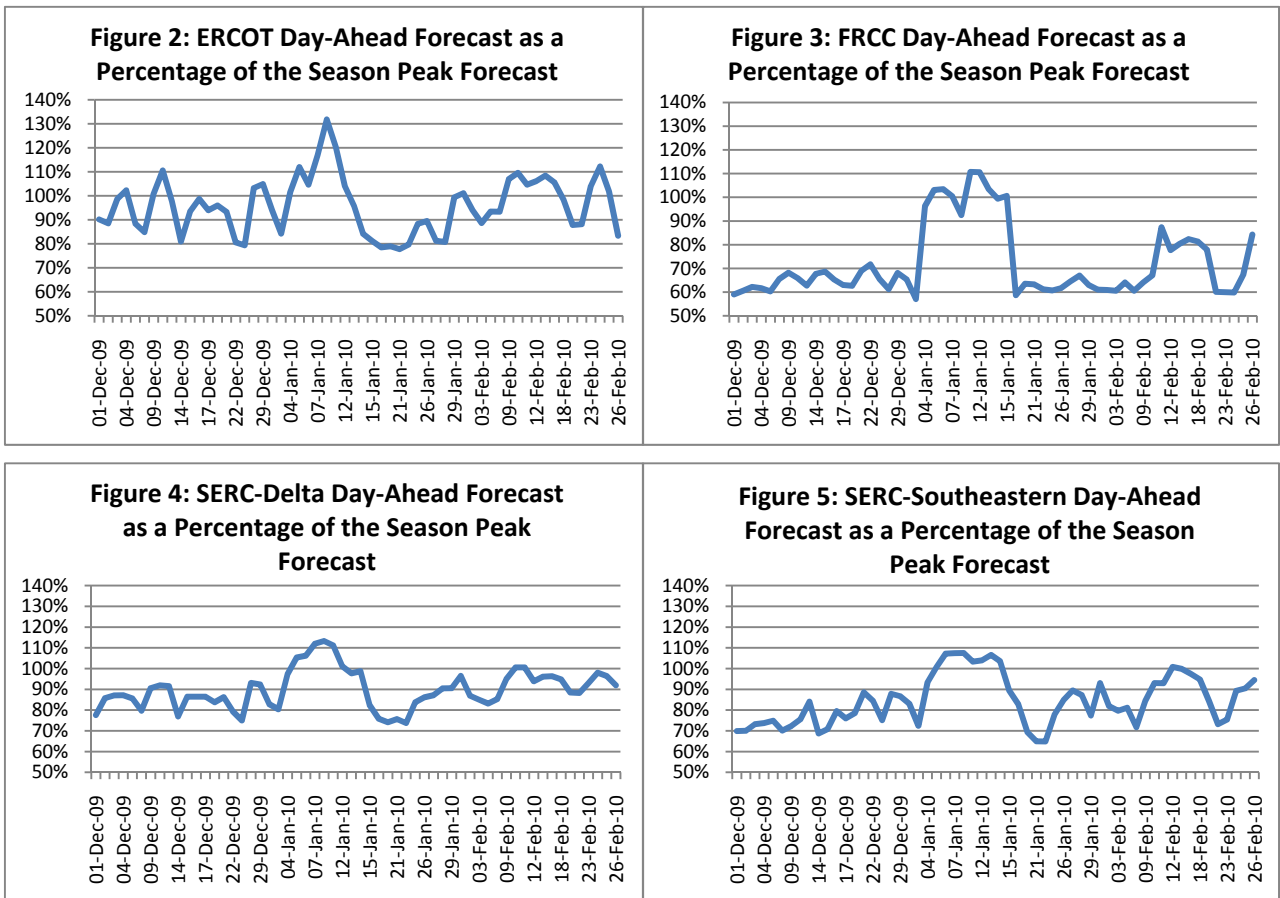
Table 1 shows the Day-Ahead Forecast compared to the Season Peak Demand Forecast by Reliability Coordinator for the 2009/2010 winter season.⁶ While most areas did not exceed the forecast, the south eastern part of the United States exceeded the forecast several times due to the colder than expected temperatures.

Table 1: Day-Ahead Forecast compared to the Seasonal Peak Demand Forecast by Reliability Coordinator

Reliability Coordinator	2009/2010 Forecast Winter Peak Demand (MW)	Day-Ahead Forecast Peak Demand (MW)	Difference (MW)	Difference (%)	Date of Peak Demand	Number of Days Day-Ahead Forecast Exceeded Seasonal Forecast
ERCOT	43,463	57,300	13,837	31.8%	8-Dec-2009	22
FRCC	45,000	49,822	4,822	10.7%	8-Jan-2010	7
ISO-NE	22,100	20,700	-1,400	-6.3%	8-Jan-2010	0
NBSO	5,505	5,205	-300	-5.4%	3-Feb-2010	0
MISORC	109,314	94,542	-14,772	-13.5%	23-Dec-2009	0
NYISO	24,998	24,300	-698	-2.8%	28-Jan-2010	0
Ontario	22,848	22,045	-803	-3.5%	29-Jan-2010	0
Quebec	36,116	34,659	-1,457	-4.0%	4-Jan-2010	0
PJM	112,742	110,023	-2,719	-2.4%	8-Jan-2010	0
SaskPower	3,214	3,147	-67	-2.1%	23-Dec-09	0
SERC-Central	43,230	41,869	-1,361	-3.1%	18-Dec-2009	0
SERC-Delta	22,064	25,006	2,942	13.3%	11-Jan-2010	8
SERC-Gateway	15,640	14,841	-799	-5.1%	4-Jan-2010	0
SERC-Southeastern	41,740	44,879	3,139	7.5%	11-Jan-2010	9
SERC-VACAR	40,437	42,342	1,905	4.7%	10-Dec-2009	1
SPP RC	54,340	41,578	-12,762	-23.5%	11-Jan-2010	0
WECC-CA-MX	37,764	38,522	758	2.0%	9-Dec-2009	2
WECC-NWPP RSG	62,526	64,456	1,930	3.1%	8-Jan-2010	3
WECC-RMRG	9,859	10,221	362	3.7%	8-Jan-2010	3
WECC-SRSG	18,574	18,035	-539	-2.9%	9-Dec-2009	0

⁵ Load Acting as a Resource: (LaaR): Customers with interruptible loads that can meet certain performance requirements may be qualified to provide operating reserves under the Load Acting as a Resource (LaaR) program. In eligible ancillary services markets, the value of the LaaR load reduction is equal to that of an increase in generation by a generating plant.

⁶ Actual peak demands were not available for all Reliability Coordinators; therefore, actuals are not included in this table.



Operations

To maintain reliability in the southeast, several operating procedures were used, including reducing voltage, deploying Demand Response, and rescheduling planned generating unit maintenance to provide necessary operating reserves. In all Regions/subregions, Reliability Coordinators sustained adequate reserves to operate their systems resulting in no uncontrolled firm demand interruptions. Maintaining operating reserves is a critical function for operating entities.⁷ During the 2009/2010 winter season, all Reliability Coordinators maintained adequate operating reserves during peak conditions.

In Québec, the actual operating reserve was close to their 1,535 MW reserve requirement at the time of peak. Using normal operating procedures, a combination of reducing nearly 500 MW of non-firm exports and deploying about 900 MW of Demand Response provided sufficient resources to meet their

⁷ Operating Reserve Margins are not comparable to Planning Reserve. An Operating Reserve Margin requirement is generally based on a Most-Severe Single Contingency, rather than a static percentage of total demand. Contingency reserve requirements vary across the Regional Entities and Reliability Coordinators. NERC Standard BAL-002-0 requires, at a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. <http://www.nerc.com/files/BAL-002-0.pdf>
 As the Planning Reserve Margin is a capacity based metric, the Planning Reserve Margin metric does not provide an accurate assessment of performance in energy-limited systems, e.g., hydro capacity with limited water resources or systems with significant variable generation penetration (see page 8 of NERC’s 2010 Annual Report on Bulk Power System Reliability Metrics Report at http://www.nerc.com/docs/pc/rmwg/RMWG_AnnualReport6.1.pdf)

required reserve levels. For SaskPower, located in the MRO region, the wind production at time of peak was an important contributor to meeting the peak demand, producing approximately 85 percent of the nameplate capacity (147 MW of 172 MW nameplate) and providing the additional operating reserves required to maintain reliability.

A Level 2 Energy Emergency Alert⁸ was called within the WECC-NWPP RSG, due to a loss of generation (375 MW). Reserve sharing was activated and reliability was maintained without incident. The activation resulted in recovery within four minutes and system reserves were restored to required levels. Other than the activation of reserve sharing agreements in the Northwest, no emergency operating procedures were invoked.

Overall, unexpected transmission outages did not result in any significant reliability issues. However, some adverse weather conditions, including frost and ice precipitation, did occur which caused some issues with accumulation on transmission lines. In Québec, this led to bulk-power transmission lines being forced out of service. Nonetheless, reliability was maintained by operating procedures that include transferring load to the New Brunswick System Operator.

With the exception of SPP, no delays in meeting in-service dates for transmission projects were reported for the 2009/2010 winter season. Continued transmission improvements in SPP were scheduled to be completed this past winter. However, some facilities were not completed and in-service until March 2010. The delay of these facilities may have contributed to four Level 5 Transmission Loading Relief (TLR)⁹ events during the winter season.

⁸ <http://www.nerc.com/files/EOP-002-2.pdf>

⁹ The NERC TLR Procedure is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. TLR incidents are reported by reliability coordinators who are required to complete the logs whenever they invoke TLR Level 2 or above. <http://www.nerc.com/page.php?cid=5|67>

Reliability Coordinator Assessment Highlights

ERCOT Reliability Coordinator

The ERCOT Region maintained reliable operations during the 2009/2010 winter period. January 2010 was an unusually cold month, with cold weather experienced throughout the state of Texas, resulting in significantly above-normal demands and energy use. The winter season peak was 55,878 MW with 4,387 MW of available operating reserves. Three 345 kV transmission lines were out of service at the time of the peak, but resulted in no reliability issues. With an installed capacity of 72,139 MW, 7,924 MW of generation outages at the time of this peak, and a responsive reserve requirement of 2,300 MW, the Region had sufficient resources installed to meet this winter peak demand.

FRCC Reliability Coordinator

In early 2010, the FRCC Region endured an unusually prolonged cold-snap that lasted more than 10 days. The average low temperature was much colder than what is normally experienced during the winter period achieving a measured peak coincidental demand of 52,368 MW. Considering the FRCC Region exceeded its previous winter peak demand by over 5,000 MW, with a large unit unavailable, the FRCC Operating Entities responded in a coordinated manner and performed admirably during the winter peak as evidenced by not shedding firm load during the extreme weather event.

SaskPower Reliability Coordinator

Saskatchewan Power Corporation, one of three Reliability Coordinators in the Midwest Reliability Organization, recorded a Peak demand of 3,231 MW on December 14, 2009. This peak occurred during a brief cold snap. The short duration of the cold weather allowed Saskatchewan to continue to operate their system in a near normal manner. Operating reserves of 368 MW of which 356 MW was on-line spinning reserve were maintained during the peak, attributing to a comfortable margin over the required reserves of 281 MW.

PJM RTO Reliability Coordinator

For the PJM RTO, the winter peak season of 2009/2010 was below forecasted load because of a mild winter. PJM experienced two significant snowstorms in February, with widespread distribution outages, which affected peak demand for those days. The winter peak day was January 4, 2010 when the metered demand reached 109,163 MW. No operating problems were experienced.

WECC Reliability Coordinator

The robust Western Interconnection power grid did not experience any significant operational issues during the 2009/2010 winter season. However, Arizona experienced significant distribution system outages and loss of firm customer demand due to a severe December cold snap and snowstorm.

Midwest ISO Reliability Coordinator

The Midwest ISO maintained adequate reserve margins to ensure that no reliability issues emerged. Despite the severe weather experienced, the Midwest ISO was able to successfully integrate its new members from Iowa to its footprint and maintain reliability throughout the 2009/2010 Winter season.

New England Reliability Coordinator

ISO New England Inc. (ISO-NE) reports there were no major operational issues that materialized which may have affected system reliability. From a weather perspective, January and February 2010 were warmer than normal, while December 2009 was colder than normal. This above-normal weather, combined with the ongoing effects of the economic recession, resulted in this winter's peak demand being significantly below prior seasonal levels. Since there were no major disruptions to regional fuel supply chains, supply-side resources had improved availability to serve regional demand.

New Brunswick System Operator Reliability Coordinator

The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes subregion, consisting of four winter peaking sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). It was a milder than usual winter and no reliability issues occurred.

New York Reliability Coordinator

It was a milder than usual winter and no reliability issues occurred. There were no significant operating problems at the times of the subregion peaks. Overall, it was an uneventful winter operating season.

IESO Reliability Coordinator

It was a milder than usual winter and no reliability issues occurred. There were no significant operating problems at the times of the subregion peaks. Overall, it was an uneventful winter operating season.

Québec Reliability Coordinator

It was a milder than usual winter and the peak demand was well below the forecast. At the time of the peak demand in late January, the system did not experience any significant operating problems. Generally, the winter season did not have significant operating problems with the exception of a period in early January when icing conditions led to several transmission circuit outages. Normal operating procedures were used to deal with this condition.

SERC Reliability Coordinators

SERC maintained adequate resources to serve peak demand in the Region despite the wide ranges of uncertainty regarding the economic and weather climates. The winter peak was reached in early January during a prolonged period of sub-freezing weather. Few issues occurred during the 2009/2010 winter period, but overall reliability concerns were insignificant.

SPP Reliability Coordinator

The SPP Reliability Coordinator (RC) footprint includes 29 Balancing Areas with 16 in SPP, 10 in SERC and 3 in MRO. This past winter, impacts from ice storms and blizzards were felt throughout the entire RC footprint. Load was up significantly, but did not create any insurmountable issues. Generating capacity was available to serve the load and loading on the transmission system did not restrict the delivery of that generation to the load.

ERCOT Reliability Coordinator

Introduction

The ERCOT Region maintained reliable operations during the 2009/2010 winter period. January 2010 was an unusually cold month, with cold weather experienced throughout the state of Texas, resulting in significantly above-normal demands and energy use.

Demand

The demand values for this report are calculated and presented for the ERCOT Region as a whole. The comparison for demand is between the seasonal forecast provided in the winter assessment and the preliminary actual peak. The preliminary actual peak demand for the 2009 to 2010 winter period was 55,878 MW on January 8, 2010, which is over 28 percent higher than the seasonal winter peak forecast of 43,463 MW predicted for February 2010. This difference was a result of system-wide temperatures averaging 33 degrees Fahrenheit below normal for the peak period throughout the region. Cold weather was experienced through most of the winter period, resulting in an abnormal increase in monthly energy demand in addition to the winter peak demand event. Even though the peak was higher than planned, no Demand Response was deployed for reliability.

Generation

The ERCOT Region had 72,139 MW of installed capacity during the winter season. At the time of the peak, 7,924 MW of generation capacity were on scheduled or forced outage. There were no reliability concerns in the ERCOT Region for delays of new units scheduled for initial operations or for delays of existing units returning to service after a scheduled outage for the 2009 to 2010 winter period.

Transmission

The ERCOT Region did not experience any reliability concerns for delays of commercial operation of new transmission elements during the 2009 to 2010 winter period. Three 345 kV lines were on outage at the time of the winter peak, but these outages did not result in reliability problems.

Operational Issues

Because of the cold weather in January that blanketed the state, precautions were taken to reduce the risk of emergency gas curtailments to units and to ensure adequate capacity would be on-line and available. ERCOT ISO recognized that system conditions may require additional generation units and started approximately 1,170 MW of capacity with longer-than-normal lead times, some in excess of 72 hours. In addition, with the potential of gas curtailment, ERCOT ISO also started an additional 1,850 MW of capacity with the ability to burn oil.

On January 9, 2010, a nuclear unit tripped with 1,229 MW of capacity due to a failure of a main power transformer. As a result, frequency dropped to 59.767 Hz. In order to maintain reliability, 922 MW of Demand Response (which was 101% of the obligated capacity) was deployed to compensate for this frequency deviation, which recovered within four minutes.

The deployment of Demand Response resources on January 9, 2010 did not occur during peak conditions and was not due to system-wide capacity or seasonal contingency reserve insufficiency. The Demand Response products provided by ERCOT ISO are not specifically designed as contingency

reserves. ERCOT ISO's approach to Demand Response enables year-round load participation in Ancillary Services markets, particularly Responsive Reserves, and supplements those Ancillary Services with short-term capacity based Demand Response that is subject to deploy during grid emergencies.

During the peak of the 2009 to 2010 winter period, there were no Special Protection Systems or Remedial Action Scheme operations. There were no voltage reductions, public appeals, nor firm or non-firm interchange transactions interrupted at the time of the peak. The greatest challenge during this period was the possible impact of gas curtailments; however, proactive actions by ERCOT ISO ensured that there were no capacity shortages.

There was no loss of firm load due to the non-performance of resources or due to transmission element outages.

Reliability Assessment Analysis

Operating Reserve for ERCOT, projected in the NERC's Morning Report, for the winter period peak was 5,404 MW; however, the actual ERCOT Region Operating Reserve at the hour of the winter peak was 4,387 MW. Per NERC Standard BAL-002, the NERC-required contingency reserve for the ERCOT region must be at least 1,354 MW, but the ERCOT Region requires at least 2,300 MW of responsive reserve service for all hours under normal conditions¹⁰. For the winter peak, the projected and actual Operating Reserves were well over the reserve requirements.

During the winter season, the unexpected loss of a main transformer at a nuclear facility was a reportable frequency event. Demand Response resources were deployed and the frequency was restored within minutes. There were no other system issues, which affected reliability during the 2009 to 2010 winter period.

Although January was a cold month, the ERCOT region maintained normal operations during the winter period resulting from effective coordination between the Resources, ERCOT Transmission Operators and the ERCOT ISO.

¹⁰ A detailed description can be found in the "2010 Methodologies for Determining AS Requirements" document found at <http://www.ercot.com/mktinfo/services/index>.

FRCC Reliability Coordinator

Introduction

The FRCC Region endured an unusually prolonged cold-snap that lasted over a week and a half at the beginning of 2010 contributing to the second coldest winter on record. Florida experienced 12 consecutive days of average low temperatures of 32°F, with the coldest day being on January 11, 2010. The average low temperature was much “colder” than what is normally (50°F) experienced during the winter period achieving peak coincidental load of 52,368 MW. Approximately 1,104 MW of Demand Response and 457 MW of voltage reduction was activated in the course of meeting system peaks.

Prior to the winter peak the FRCC Reliability Coordinator along with its Operating Entities cancelled all scheduled transmission outages. The State Capacity Emergency Coordinator issued a capacity advisory for several days and convened daily reliability calls with FRCC BAs, TOPs, and the three gas pipeline operators serving the Region. Close Regional coordination ensured that the FRCC Operating Entities were able to perform reliably and admirably during the winter peak as evidenced by not having to shed any firm load during the extreme weather event.

Demand

Forecasted peak demand values for this assessment are consolidated by the Reliability Coordinator from the forecasted peaks of the individual Balancing Authorities to obtain one forecasted regional value for the next day. The peak demand analyses within this assessment will primarily compare the regional seasonal forecast to the day-ahead forecast.

The winter seasonal assessment for the 2009/2010 winter forecasted a regional peak demand of 44,446 MW (non-coincident) compared to the daily forecast of 49,822 MW (non-coincident) and to the measured coincidental peak of 52,368 MW (Approximately 1,104 MW of Demand Response was activated during system peak) which occurred on January 11, 2010. The seasonal assessment forecast was prepared in April 2009.

The FRCC Region endured an extreme weather period due to an unusually prolonged cold-snap that lasted over a week and a half at the beginning of 2010 contributing to the second coldest winter on record. Florida experienced 12 consecutive days of average low temperatures of 32°F weather with the coldest day being on January 11, 2010. This was much longer than the typical cold-snap that lasts only two or three days. This cold-snap had an average low temperature of 32°F throughout the FRCC Region that was much “colder” than what is normally (50 degrees) experienced during the state’s winter period and extended deeper into Southeast Florida containing some of the larger load centers of the FRCC region. In addition, the daytime average high temperature was 49°F compared to the normal high temperature of 68°F, which prevented homes from warming up during the day and resulted in higher than normal daily energy use.

Generation

There were no delays in the initial operation of new units and no delays that caused a reliability concern were experienced in returning units to service following a scheduled maintenance outage. During the seasonal peak for the region, some planned unit outages were re-scheduled to later dates in order to

ensure all regional generation resources were available to meet system demands within the RC footprint.

Transmission

There were no delays that caused a reliability concern in achieving commercial operation of new transmission facilities during this winter season.

Operational Issues

There was no loss of firm load during the winter peak event and there were no bulk transmission outages during the event.

The three gas pipelines serving the Region performed as designed and without incident; however, to preserve the reliability of the pipelines, many generator operators opted to operate some of their units on liquid fuel in an effort to conserve natural gas and meet usage requirements.

Prior to the peak, the FRCC Reliability Coordinator and its Operating Entities cancelled all scheduled transmission outages. Based on pre-determined forecast temperature triggers, the State Capacity Emergency Coordinator (SCEC) began issuing capacity advisories several days prior to the event and convened daily reliability calls with the FRCC BAs, TOPs, and the three gas pipeline operators (transporters). In addition, during the peak period of the event, two BAs requested the initiation of Energy Emergency Alerts (EEAs) on their behalf by the FRCC RC.

During the actual peak demand morning, approximately 1,104 MW of Demand Response was activated. The expected Demand Response based on planning assumptions for programs that were exercised, was 1,192 MW. The difference between the expected Demand Response and the actual may be used to update the models used to forecast expected Demand Response during peak conditions.

There were no SPS or RAS operations during the winter peak event. A 2.5 percent voltage reduction was implemented during the actual peak morning of the event. It is estimated that the demand was reduced by 457 MW as a result of implementing voltage reduction without impacting existing firm and non-firm transactions.

Emergency imports were called for during the peak. Some BAs requested the initiation of Energy Emergency Alerts, resulting in additional transaction coordination between the FRCC RC and Southeastern RC for a net import total of 50 MW.

Typically, three or more consecutive days of extreme cold weather will create high demands in Florida, and may stress the fuel supply. In response, Generating Operators will switch to liquid fuel to ensure there is sufficient gas capacity to serve the peak load.

Reliability Assessment Analysis

The actual Operating Reserve was 4,035 MW, which was obtained by starting with the total resource capacity projected for system peak, subtracting the preliminary “actual” peak provided by the FRCC RC and adding the unused available Demand Response. The FRCC Region required minimum operating reserve requirement is 930 MW.

The FRCC's largest nuclear plant was not available for this event due to an extended maintenance outage. However, sufficient emergency power was procured from the SERC-Southeastern subregion to avoid shedding firm load. The FRCC Region had sufficient capacity to meet the peak load and in some cases the RC had to perform real-time power flow studies to assess the impact of transactions.

The FRCC Operating Reliability Subcommittee (ORS) is in the process of developing lessons learned and recommendations going forward. (1) ORS plans to draft a check sheet for future capacity advisories and alerts. The check sheet will cover items to review during the pre-event conference calls such as review operation on liquid fuel, ensure permitting is adequate, be aware of de-mineralized water constraints and any other environmental constraints which may impact dispatch. (2) FRCC has the ability to update system models to reflect future operating conditions such as updating of appropriate facility ratings and adjusting for changes in merit order to account for environmental constraints that affect dispatch. (3) Capacity Assessment: Investigate a change request on the RC's capacity monitoring application to allow a BA to enter multiple peaks for a given day.

Other Issues

Although the FRCC exceeded its previous peak by over 5,000 MW or more than 10 percent, the FRCC Operating Entities performed as expected with no uncontrolled firm load shed during the peak, with a large unit out. Implementaion of any changes from the lessons learned will position the FRCC Region to meet the challenges associated with capacity advisories and alerts in the future.

New England Reliability Coordinator

ISO New England Inc. (ISO-NE) reports that within New England, during the 2009/2010 winter, there were no major operational issues that materialized which may have impacted system reliability. From a weather perspective, January and February 2010 were warmer than normal, while December 2009 was colder than normal. This “above-normal” weather, combined with the ongoing effects of the economic recession, resulted in this winter’s peak demand¹¹ being significantly below prior seasonal levels. In addition, since there were no major disruptions to regional fuel supply chains, supply-side resources had improved availability to serve regional demand.

ISO-NE is the Regional Transmission Operator (RTO) for the six-state New England region. ISO-NE is responsible for the reliable operation of the bulk power system, administration of the region’s wholesale electricity markets, and management of the comprehensive planning process.

Since the majority of New England’s generation fleet is primarily gas-fired¹², electric system operations during winter have been concerned historically with the supply and availability of natural gas. In addition, since regional gas local distribution companies (LDCs) are supplying fuel to the residential and commercial sectors for space heating needs, competition between the gas and electric sectors during winter is at its peak. However, the recent commercialization of several new regional gas sector projects has resulted in increased access to new gas supplies and improved deliverability throughout the region. Because of these and other infrastructure enhancements, there were no major fuel supply constraints reported within the gas-fired generation sector and system operation during this past winter was manageable.

Demand

Within the Northeast Power Coordinating Council Inc. (NPCC), ISO-NE is the Balancing Authority for the New England subregion and it subsequently reports only one (1) subregional electrical peak demand value for the entire Control Area.

The forecast for the 2009/2010 winter peak demand was 22,100 MW. The vintage of the 2009/2010 winter peak demand forecast was April 2009 and the forecast was published within ISO-NE’s annual publication of the report entitled “2009-2018 Forecast Report of Capacity, Energy, Loads and Transmission” (CELT Report), which was posted on April 15, 2009.¹³ The forecast for the 2009/2010 winter peak demand corresponds to a 50/50¹⁴ reference case peak demand forecast. The actual winter peak demand was 20,791 MW, which took place on December 17, 2009. The actual winter peak seasonal demand was then weather normalized to 22,030 MW, which is approximately 70 MW below the forecast value. Normalization is used here to provide a comparison of the demand to what would be expected for normal historical weather conditions. This translates into a 2009/2010 winter peak demand load forecast difference of only 0.3 percent.

¹¹ As well as the overall energy consumption for the period December 2009 through February 2010

¹² Summer 2010 capacity ratings shows primary-fueled, natural gas-fired generation totaling 13,181 MW. When compared to the generation fleet’s total capacity of 31,965MW, this amount represents 41.2 percent.

¹³ <http://www.iso-ne.com/trans/celest/report/index.html>

¹⁴ This peak demand forecast has a 50% chance of being exceeded.

No unusual or abnormal weather conditions were experienced in New England at the time of the winter peak demand. The winter peak demand occurred at 6 p.m. EST on December 17, 2009, with regional weather conditions at 15°F with a -3°F dew point.¹⁵ No unusual or abnormal weather conditions were experienced in New England over the 2009/2010 winter.

At the time of the winter peak demand, there was no activation of Demand Response. However, approximately 766 MW of Other Demand Resources (ODRs) were in place and ready for activation if required for system reliability.

Generation

There were no expected delays to any new generation before the 2009/2010 winter.

During the 2009/2010 winter, there were some concerns due to a couple of extended generation outages early in December 2009 amounting to approximately 1,000 MW. However, these extended generation outages were completed prior to the winter peak demand on December 17, 2009, and in addition, there were other units that were available for dispatch to cover system conditions that may have impacted system reliability.

Transmission

There were no reliability concerns created by delays in achieving commercial operation of new transmission facilities during the 2009/2010 winter and because of this, no special operating procedures were needed to maintain system reliability due to delays in transmission facility commercialization.

Operational Issues

On February 25, 2010, a storm crossed southern Maine and south central New Hampshire with winds gusting up to 89 miles per hour along with heavy wet snow. It is estimated that 255,000 customers were without power, equaling approximately 510 MW of load. The outages were a result of distribution problems in Maine and New Hampshire. This was reported in an OE-417 report to the U.S. DOE. There was no loss of firm load due to the non-performance of any bulk power system resource or transmission outage.

There were no major issues with regional fuel supplies of coal, oil (heavy or light), natural gas or LNG during 2009/2010 winter. However, the Sable Offshore Energy Project (SOEP) did experience several unplanned outages at its natural gas production facilities in Atlantic Canada. During these temporary gas supply disturbances, the Canaport LNG facility¹⁶ was able to deliver replacement gas to the market. No major or prolonged fuel-supply curtailments to gas-fired units or issues associated with natural gas quality or interchangeability between fuels were reported.

During these three winter months of December 2009 and January and February 2010, ISO-NE did not need to implement any Emergency Operating Procedures (EOPs). However, during the same three-month timeframe, ISO-NE did invoke Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert* (M/LCC2) on twelve occasions. Four M/LCC2 declarations in December 2009 were to maintain sufficient operational capacity across all of New England. The majority of the remaining M/LCC2

¹⁵ This regional weather is defined as dry-bulb temperature (°F) which is a weighted value from eight New England weather stations.

¹⁶ Located in Saint John, New Brunswick.

declarations in January and February were to curtail real-time electric supply contracts in order to maintain operating reserves.

On Sunday, March 15, 2010, ISO-NE implemented Operating Procedure # 4 - *Action During a Capacity Deficiency* (OP-4) at 20:30 just following the evening peak. Actions 1 and 6 of OP-4 were declared to allow the area to become deficient in meeting its 30-minute reserve requirement (normally 600 MW) for the 2nd largest contingency. This implementation of OP-4 was due to the unplanned, forced outage (tripping) of regional generation. All actions of OP-4 were cancelled at 22:00 that same day.

There was no need to invoke Demand Response resources for reliability purposes for use as contingency reserves throughout the 2009/2010 winter.

There were no operation(s) of Special Protection Systems or Remedial Action Schemes reported on the New England bulk power system during the winter peak of 2009/2010. There was only one triggering of an Emergency Operating Procedure during the winter of 2009/2010 (on March 15, 2010), however during this event, there was no need for voltage reductions or public appeals.

There were no firm interchange transactions interrupted over the winter peak of 2009/2010.

ISO-NE regularly curtails non-firm, “real-time only” interchange transactions (imports and exports), if those transactions have not been previously scheduled within the ISO-NE Day-Ahead Market (DAM) for the current Operating Day. ISO-NE will declare Master/Local Control Center Procedure 2 - *Abnormal Conditions Alert* (M/LCC2) when the Control Room is required to curtail these transactions to maintain operating reserves. Curtailments are a normal part of the interchange business process.

As detailed earlier, during the 2009/2010 winter, ISO-NE did invoke M/LCC2 on twelve occasions.

One of the most important challenges of operating the bulk power system in New England is managing the large quantity of long, lead time (start-time) fossil-based generation relative to quick-start, “peaking” generation, with respect to contingency recovery. This issue requires ISO-NE to ensure that it has a high level of accuracy in forecasting demand and the subsequent scheduling and commitment of regional generation to satisfy daily peak demand and operating reserve requirements.

Reliability Assessment Analysis

For the winter peak demand day of December 17, 2009, the following information was obtained from ISO-NE’s Morning Report, which is the final projection for the operational day. The Operating Reserves on peak are calculated by the following formula: Total Available Capacity¹⁷ (22,989 MW) minus Peak Load Forecast (20,680 MW) minus Operating Reserve Requirement (2,288 MW) equals Operating Reserve Surplus (21 MW) or deficiency (0 MW).

The Operating Reserve Margin is calculated by the following formula: Estimated Operating Reserve minus Operating Reserve Requirement equals the Operating Reserve Margin. The Estimated Operating

¹⁷ Includes installed seasonal capacity (34,020 MW) plus capacity bids > seasonal ratings (124 MW) plus any pre-EOP dispatchable loads (0 MW) minus generation outages and reductions (3,828 MW) minus all uncommitted generation (7,214 MW), plus net of firm capacity purchases minus sales (-113).

Reserves for the winter peak demand day were approximately 2,309 MW.¹⁸ The Total Operating Reserve Requirement for the day was 2,288 MW, thus resulting in an Operating Reserve Margin of only 21 MW.

The actual operating reserves over the peak hour were 2,154 MW, which was subsequently satisfied with an actual surplus of 200 MW over the real-time requirement of 1,954 MW.

Since there were no major issues, conditions or concerns, during the 2009/2010 winter, there were no major conclusions or *lessons-learned* that could be drawn or observed from system operations during the 2009/2010 winter.

Other Issues

There were no invocations of ISO-NE's Cold Weather Watch, Warning or Event, as defined within Appendix H of Market Rule 1 – *Operations During Cold Weather Conditions*.¹⁹ Appendix H is triggered by the combined effects of severe winter weather and a shortage of sufficient operable capacity to supply projected load. Since severe winter weather never materialized and there were no major fuel supply disturbances on the system, operable capacity margins remained positive, thus eliminating the need for Appendix H invocation. Early communication between ISO-NE and market participants allowed them to prepare for approaching cold weather, and gas-fired unit availability was sufficient. Communication and coordination between ISO-NE and the gas control divisions of the regional pipelines in preparation for cold weather was excellent. For most of the winter, very few oil-fired fossil units cleared in the Day-Ahead Energy Market and hardly any supplemental reliability commitment of units was required.

Two new LNG facilities, 1) Canaport LNG - located in Saint John, New Brunswick and 2) the Northeast Gateway Deepwater Port - located offshore of Gloucester, MA, combined with expanded natural gas pipeline infrastructure into and throughout New England, provided ample natural gas supplies to regional, gas-fired generation even on the coldest days of the 2009/2010 winter.

While natural gas remains the dominant fuel within New England's electric generation sector, the region's diversity and expected reliability of natural gas supply has improved, resulting from a new LNG terminal that went into commercial operation during the summer of 2009. In addition, several pipeline expansion projects have been designed to improve the ability to deliver LNG and other sources of natural gas to the region.

To help mitigate the dependency on natural gas as a single fuel when gas prices are high or supplies are temporarily scarce, about 25.4 percent of the region's generating plants (about 8,106 MW) have dual-fuel capability, the ability to switch between oil and gas, when one fuel source is either constrained or uneconomical.

Contingencies on the regional gas supply and transmission system could limit gas deliveries to generators anytime of the year. Effective communications between gas and electric industry operations helps mitigate these and other reliability concerns.

Gas quality and interchangeability will remain a concern as more gas supplies are integrated into the supply mix, which can result in different gas compositions that can affect the operation of some types of

¹⁸ This total is comprised of 1,671 MW of Ten Minute Estimated Reserves and 638 MW of Thirty Minute Estimated Reserves.

¹⁹ http://www.iso-ne.com/regulatory/tariff/sect_3/1-24-10_mr1_appendix_h.pdf

gas turbines. The natural gas and electric power industries are exploring options to minimize potential problems due to variations in gas quality.

Aging coal and oil-fired generation are facing additional economic pressures from environmental regulations. The possibility of these units being replaced or repowered with natural gas could increase the region's dependency on natural-gas-fired generation. Other environmental regulations are promoting the development of renewable resources and energy efficiency. The addition of these supply and demand-side resources would reduce the region's dependency on natural gas fired generation.

NBSO Reliability Coordinator

The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area, consisting of four winter peaking sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). It was a milder than usual winter and no reliability issues occurred.

Demand

The Maritimes Area load is the mathematical sum of the peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, the Maritimes Area is reported as an annual single peak load. Monthly, weekly and day ahead assessments are also done in order to provide the most up to date information possible. Hourly assessments are done in real time.

Based on the Maritimes Area CO-12 NPCC Reliability Assessment Winter 2009/2010 report done in the early fall of 2009 a demand forecast peak of 5,514 MW was predicted to occur this winter period, December through February. The actual winter peak was 5,205 MW and occurred on February 3, 2010 HB 07:00 AST. The actual peak was approximately 6 percent less than the forecasted peak and can be attributed to milder than expected winter temperatures.

The Maritimes Area did not experience any unexpected extreme or adverse weather conditions and it did not use Demand Response measures.

Generation

There were no delays to new generation additions or delays in the return-to-service of existing generating units that caused a reliability concern

Transmission

There were no delays in achieving commercial operation of new transmission during this winter season.

Operational Issues

The Maritimes Area did not experience any loss of firm load due to the non-performance of a bulk power system resource, nor did it experience any loss of firm load due to the loss of a bulk transmission outage.

During 2009/2010 winter in the Maritimes Area, there was no need for use of the following:

- Actions because of fuel supply problems.
- Emergency Operating Procedures.
- Use of Demand Response deployed for reliability purposes as contingency reserves.
- Special Protection System or Remedial Action Scheme operations
- Voltage reductions or public appeals
- Firm interchange transactions which were interrupted
- Non-firm interchange transactions that were interrupted

The Maritimes Area is a winter peaking system and, therefore, can be affected by adverse weather conditions, which could lead to transmission outages. Because the Maritimes Area has a very robust transmission system, prolonged transmission outages rarely occur.

Reliability Assessment Analysis

The actual Operating Reserve on peak was 752 MW. The Maritimes Area assesses its seasonal resource adequacy in accordance with NPCC Directory #1, Appendix F *Operational Planning Coordination* procedure.²⁰ As such, the assessment considers the regional Operating Reserve criteria; 100 percent of the largest single contingency and 50 percent of the second largest contingency. The Operating Reserve exceeded the Operating Reserve Requirement. As stated above, as long as the Operating Reserve exceeded the largest single and second largest contingencies then the requirement has been met.

The Maritimes experienced a much milder than expected winter this past season. The weather condition that could have affected reliability the most is freezing rain that limits or shuts down some of the wind farms. This issue, however, did not affect the overall reliability of the Maritimes Area.

The Maritimes Area did not experience any unexpected conditions that affected reliability. Because there were no unusual operating conditions during the winter there were no lessons learned.

²⁰ <http://www.npcc.org/documents/regStandards/Procedure.aspx>

Midwest ISO Reliability Coordinator

The Midwest ISO's scope of operations covers 13 states and one Canadian province. On September 1, 2009, the Midwest ISO worked successfully in integrating three new transmission owners to the Midwest ISO membership: MidAmerican Energy Company, Muscatine Power and Water, and the Municipal Electric utility of the city of Cedar Falls, Iowa. With the addition of these new members, the Midwest ISO maintained reserve margins to ensure that no reliability issues emerged throughout the 2009/2010 Winter season despite the adverse weather.

Demand

The Midwest ISO is a Reliability Coordinator in the RFC, MRO, and SERC Regions. The peak demand values and other data are calculated with respect to the entire Midwest ISO footprint during the 2009/2010 Winter season. Comparing the instantaneous peak demand of 87,208 MW to the coincident forecast of 85,300 MW reflects roughly a 2.2 percent difference. The non-coincident peak demand forecast of 94,542 MW (day-ahead) was 86.5 percent of the non-coincident peak demand forecast of 109,314 MW (seasonal) showing a difference of 14,772 MW.

The demands as reported by Network Customers are weather normalized, or 50/50, forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50 percent chance the actual load will be higher and a 50 percent chance the actual load will be lower than the forecast.

Regarding the unexpected weather conditions referred to above, the peak month during the 2009/2010 Winter season, December 2009, was characterized by very low temperatures and severe winter storms, which appeared across the Midwest footprint. These weather conditions contributed to Midwest ISO reaching an all-time instantaneous peak load during the winter season.

Despite the severe weather conditions experienced, no demand resources (namely interruptible load and direct control load management) were deployed during the 2009/2010 Winter season.

Generation

There were there no reported delays which caused a reliability concern to new (planned in Seasonal Assessment) units or initial operation for this season. Additionally, there were there no reported delays which caused a reliability concern to existing units being brought back into service after scheduled outages for this season.

Transmission

There were no reported delays in achieving commercial operation of new transmission during this season.

Operational Issues

Despite the severe weather conditions experienced over the 2009/2010 Winter season, there was no loss of firm load reported due to the non-performance of a bulk power system resource, no loss of firm load was reported due to bulk transmission outages, and there were no reports of fuel situations impacting the use of resources. Although MISO can also utilize Emergency procedures if peak demands are higher than expected, there were no reported Emergency Operating Procedures that were deployed

to maintain reliability. Finally, in the face of the severe weather conditions observed, no demand resources (namely interruptible load and direct control load management) were deployed during the 2009/2010 Winter season.

During peak, there were no reported Special Protection Systems (SPS) or Remedial Action Scheme (RAS) operations. Similarly, there were no reported voltage reductions or public appeals implemented and no reported firm interchange transactions or non-firm interchange transactions, which were interrupted during peak. There are currently no important challenges identified to report regarding the operation of the bulk power system in the Midwest ISO.

Reliability Assessment Analysis

The actual Operating Reserve on peak was 33,453 MW, which was above the Projected Reserves of 26,926 MW and well above the minimum Required Operating Reserve of 2,563 MW. The actual Operating Reserve Margin of 38.4 percent was calculated using the instantaneous peak demand of 87,208 MW and the adjusted resources of 120,661 MW, which is comprised of the forecasted internal and external designated capacity resources.

There were no reported system issues or conditions that impacted reliability during peak or at times other than peak. There were no major lessons learned from the 2009/2010 Winter season.

Other Issues

Despite the severe weather experienced, the Midwest ISO was able to successfully integrate the new Iowa members to the footprint and maintain reliability throughout the 2009/2010 Winter season.

New York Reliability Coordinator

The New York Independent System Operator (NYISO) operates the high-voltage transmission network, administers and monitors the wholesale electricity markets, and plans for the state's energy future. The NYISO is responsible for the reliable operation of New York's nearly 11,000 miles of high-voltage transmission and the dispatch of over 500 electric power generators. The NYISO peak demand occurs during the summer season. This winter was milder than usual and no reliability issues occurred. There were no significant operating problems at the times of the subregion peaks. Overall, it was not an eventful winter operating season.

Demand

The New York Balancing Authority 2009/2010 winter coincident peak load forecast was 24,998 MW, which was 295 MW lower than the forecast of 25,293 MW for the 2008/2009 winter. The actual system coincident peak for the 2009/2010 winter was 24,074 MW, which was 599 MW lower than the 24,673 MW 2008/2009 actual winter peak. The 2009/2010 actual peak was lower due to the impact of the current economic recession on electric energy consumption.

Weather conditions for the 2009/2010 winter had temperatures that were lower than those at the time of the all-time winter peak of 25,541 MW, reached on December 20, 2004; therefore, the peak was not reached during this winter season for the New York Control Area (NYCA). During the 2009/2010 winter adverse or extreme weather conditions were not experienced in the NYCA. Emergency demand programs were not used during 2009/2010 winter for NYCA.

Generation

There were no new unit initial operations during the 2009/2010 winter for the NYCA and there were no delays which caused reliability concerns to existing units being brought back into service after a scheduled outage within the NYCA.

Transmission

During the 2009/2010 winter there was no new transmission added within the NYCA.

Operational Issues

During the 2009/2010 winter, there were no losses of firm loads due to the non-performance of the resources available or transmission within the NYCA bulk power system. In addition, there were no fuel situations that impacted the use of resources.

During the 2009/2010 winter, there were no reliability events, which required the deployment of Emergency Operating Procedures.²¹

During 2009/2010 winter in the NYCA there was no need for use of the following:

- Demand Response deployed for reliability purposes as contingency reserves.

²¹ Information on NYCA Emergency Operating procedures can be obtained within the NYISO website at the following link:
http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp

- Special Protection System or Remedial Action Scheme operations
- Voltage reductions or public appeals
- Firm interchange transactions which were interrupted
- Non-firm interchange transactions that were interrupted

Within the NYCA, there is no single outstanding challenge aside from the typical challenges in operating the Bulk Power System.

Reliability Assessment Analysis

The actual operating reserve on peak was 3,495 MW for the NYCA during 2009/2010 winter. The Operating Reserve Requirement is 1.5 times the Single Largest Contingency. The Minimum Operating Reserve required for Peak day December 17, 2009 was 1,800 MW. The actual was well above the required.²²

There were no major issues or unexpected conditions encountered within the NYCA bulk power system during the 2009/2010 winter, which had a major impact on the reliability of the system.

²² The Minimum Operating Reserve Requirement of the NYCA is defined as:

1. Sufficient Synchronized Reserve Available in 10 minutes to replace one-half of the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria multiplied by the contingency reserve adjustment factor.
2. Sufficient Reserve Available in 10 minutes (which includes synchronous reserve available in 10 minutes) to replace the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria multiplied by the contingency reserve adjustment factor.
3. Sufficient Reserve Available in 30 minutes (which includes reserve available in 10 minutes) equal to one and one-half times the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria.
4. Sufficient Reserve in 10 minutes to return the system to a Normal State following the most severe transmission contingency multiplied by the contingency reserve adjustment factor.

At all times sufficient 10 Minute Reserve shall be maintained to cover: 1) the energy loss due to the most severe Normal Transfer Criteria contingency within NYCA or 2) the energy loss associated with recallable import transactions from another control area, whichever is greater.

PJM RTO Reliability Coordinator

Along with being a Regional Transmission Operator, PJM is a Reliability Coordinator in the RFC and SERC Regions. PJM is the largest single Balancing Authority in the world with an all-time peak load of over 145,000 MW.

Demand

The PJM RTO²³ preliminary actual peak demand was 104,543 MW, which was 8,207 MW below the seasonal assessment peak demand forecast of 112,750 MW. The weather-normalized actual peak demand is not available yet. The PJM area did not experience weather conditions that were as cold as typical winter peak day conditions so PJM did not reach its forecasted demand.

PJM experienced two significant snowstorms in February, with widespread distribution outages, which affected peak demand for those days. These outages did not coincide with the overall peak for this winter. There was no demand response used at the time of the peak.

Generation

There were no delays to new (planned in Seasonal Assessment) unit initial operation for this season. There were no delays to existing units returning into service after a scheduled outage.

Transmission

There were no delays in achieving commercial operation of new transmission during this season.

Operational Issues

There was no loss of firm load due to the non-performance of a bulk power system resource or transmission outage. There were no fuel situations, which impacted the use of resources this winter. Only low-level alerts and warnings were issued by PJM operations this winter. No emergency procedures were initiated.

Demand Response was not deployed as contingency reserves at any time throughout the winter season. No SPSs operated this winter. No voltage reductions or public appeals were implemented. No firm transactions were interrupted. TLR 3s (curtailment of non-firm transactions) were occasionally called during the winter season.

Reliability Assessment Analysis

Peak day was January 4, 2010 and the Required Operating Reserve was 6,173 MW. The actual Reserve was 31,078 MW, which was well above the requirement as would be expected for a summer peaking Balancing Authority. The typical PJM Reserve Requirement is approximately 6 percent of the forecast daily peak but the actual calculation requirements are in Section 3 of PJM's Manual 10 *Pre-Scheduling Operations*.²⁴

²³ The peak demand values and other data presented in this report is on a PJM basis

²⁴ <http://www.pjm.com/~media/documents/manuals/m10.ashx>

IESO Reliability Coordinator

The Independent Electricity System Operator (IESO) directs the operations of the IESO-controlled grid (ICG) and administers the electricity market in Ontario. The ICG experiences its peak demand during the summer, although winter peaks still remain strong. The 2009/2010 winter season was a milder than usual winter and no reliability issues occurred. There were no significant operating problems at the time of peak. Overall, it was not an eventful winter operating season.

Demand

The peak demands presented in this report are for the Ontario Independent Electricity System Operator (IESO)-controlled grid. The forecasted peak for the 2009/2010 winter was 22,848 MW. The actual peak demand for the winter occurred on January 4, 2010 and was 22,045 MW. On a weather-corrected basis, the peak was a bit higher at 22,378 MW. The winter was milder than normal and bereft of any significant cold spells. At the time of the winter peak, there was 2.2 MW of Demand Response activated.

Generation

A new generator, East Windsor Cogeneration, became operational without any delay before the winter period. There were no reliability concerns from any planned outages or extensions to outages.

Transmission

There were no transmission line projects scheduled to come into service before last winter. The two transmission facilities listed below were commissioned as scheduled.

- Four 230 MVAR shunt capacitor banks at Middleport TS
- Two 250 MVAR shunt capacitor banks at Nanticoke TS

Operational Issues

For the 2009/2010 winter, there were no occurrences of firm load loss due to the non-performance of a bulk power system resource or transmission outages. In addition, there were no occurrences where resources were impacted due to fuel situations. Emergency Operating Procedures were not required to maintain reliability. Demand Response was not required for reliability purposes.

During the peak hour, reliability actions were not required, which included operation of Special Protection Systems or Remedial Action Schemes, voltage reductions, public appeals, and interruption of interchange transactions. Over the course of 2009/2010 winter Ontario did not experience any challenges that affected the reliability of the bulk power system.

Reliability Assessment Analysis

Ontario is required to carry three types of reserves; 10-minute non-spinning reserve, 10-minute spinning reserve and 30-minute reserve. The total required reserve on peak hour was 1,620 MW, while the total 10-minute reserve required was 1,080 MW. As Ontario participates in the NPCC Shared Activation of Reserve and Regional Reserve Sharing Energy procedure, it is able to reduce the 10 minute and total operating reserve (OR) requirement by 100 MW. Over the course of the peak hour, Ontario had 1,520 MW of total OR scheduled, and a minimum of 980 MW of 10-minute reserve scheduled. The total reserves available at the time of the winter peak were 9,303 MW.

Québec Reliability Coordinator

Introduction

The Québec Reliability Coordinator area is a separate Interconnection from the Eastern Interconnection into which other NPCC Areas are interconnected. TransÉnergie is the Transmission Owner and Operator in Québec and has interconnections with Ontario, New York, New England and the Maritimes. Interconnections consist of either HVdc ties or radial generation or load to and from the neighboring systems. The population served is around 7 million and the Québec Area covers about 1,668,000 km (644,300 square miles). Most of the population lives in the St. Lawrence River basin, and the largest load area is in the southwest part of the province, mainly around the Greater Montréal area, extending downriver to the Québec City area.

The Québec Area is winter peaking. There is only one Balancing Authority within the sub-region. Summer peak load is typically about 55 percent of winter peak load. The all-time internal peak demand was 37,230 MW set on January 16, 2009. Summer peak demands are in the order of 21,000 MW. Installed capacity in 2010 is around 42,300 MW of which 39,700 MW (94 percent) is hydroelectric capacity. Transmission line length totals about 33,244 km (20,658 miles).

Demand

The Load Serving Entity in Québec is Hydro-Québec Distribution (HQD). Hydro-Québec Distribution conducts its load forecast for the Québec Balancing Authority area represented as a single entity. There is no demand aggregation. The Area's peak forecast information is coincident. From this peak forecast information, TransÉnergie (acting as Reliability Coordinator) issues annual Internal Demand Forecasts, with accompanying monthly, weekly, daily, and hourly forecasts for System Control's real-time use.

The 2009/2010 winter internal peak demand was 34,659 MW and occurred on January 29, 2010 at 18h00 EST. The total system demand, which includes exports, was 38,068 MW at the time of peak. The annual internal demand forecast, based on Hydro-Québec Distribution's August 2009 forecast, was 36,116 MW.

The 2009/2010 winter experienced normal to above normal temperatures and no sharp cold snap occurred. January 29 (Peak day) was the first of a short two-day colder episode. Winds were present all over the Balancing Authority area. In Montréal, average wind speed on the peak day was 40 km/h (24 mph) with gusts of 48 to 58 km/h (29 to 35 mph) during about 10 hours preceding the peak time. Sustained snow was observed over the central and eastern parts of Québec on the peak day.

Some adverse weather conditions were experienced during the Winter Operating Period. On January 4, 5 and 6, 2010, Central and Southern Québec saw icy drizzle mixed with wet snow. Substantial accumulation was measured in specific measurement stations and this weather episode led to the Line 7018 event, discussed below. Two more ice precipitation and frost formation events occurred (one on December 27, 2009 in Matapédia and another on January 3, 2010 on the North Shore), impacting local subsystems and leading to the Lines 3089-3090 and Line 3039 events also discussed below.

Of the two Interruptible Load programs available in Québec, only the Hydro-Québec Production (HQP) program was called during peak hours on January 29. At peak time, 911 MW of interruptible load had been called 24 hours beforehand, based on market conditions.

Generation

As mentioned in the NERC 2009/2010 Winter Reliability Assessment, no new resources were expected to be placed in service for this period. Therefore, no delay in any unit initial operation was experienced or caused any reliability concern. Moreover, there were no delays to existing units being brought back into service after a scheduled outage for this Winter Operating Period.

Transmission

As mentioned in the NERC 2009/2010 Winter Reliability Assessment, the second 625 MW HVdc converter of the Outaouais Interconnection with Ontario was commissioned as scheduled during November 2009. This interconnection is integrated into the Québec system through a double-circuit 315 kV line. There were no delays in achieving commercial operation. There were no reliability concerns. Construction of a second double-circuit 315 kV line is now being finalized to allow full-time use of the full 1,250 MW capacity. This line will be in service in June 2010.

Operational Issues

Two ice and frost episodes occurred on 315 kV lines and led to loss of some load. Line 3039 (315 kV) between Montagnais and Normand substations (in the St Lawrence North Shore area) was out of service from January 3 to January 9, 2010 due to an ice storm. The storm damaged phase conductors along the line. Prioritized loads at Normand and Fermont substations along with the Hart Jaune Generating Station were transferred to Wabush substation in Labrador for the duration of the outage. Load was transferred back to its normal feed on January 9.

On December 24, 2009, heavy frost formation on Lines 3089 and 3090 between Rimouski and Matapédia substations caused faults and a permanent trip-out of both lines. The 315 kV feed to Matapédia substation was lost with 245 MW of exports to New Brunswick at Eel River and 160 MW of Hydro-Québec load. A restoration procedure was initiated through New Brunswick for the Québec load, but due to a problem with a disconnect switch at Eel River, this procedure took about 11 hours. Load was finally restored and remained on New Brunswick until December 30. Between January 7 and 12, 2010 more heavy frost conditions occurred on Lines 3089 and 3090 and Québec load had, again, to be transferred to New Brunswick for that period. Normal operations were restored on January 12.

No fuel situations impacted the use of resources during the Winter Operating Period. It was mentioned in the NERC 2009/2010 Winter Reliability Assessment that fossil fuel generation stations are used for peaking purposes only. The energy contribution of these generating stations is minimal. All have adequate fuel reserves as part of their installations and all are fueled at the beginning of the Winter Operating Period.

No emergency procedures were deployed to maintain reliability.

Demand Response is not deployed as contingency reserve in Québec. However, it is used ahead of time to meet load following capability, when necessary. On December 17, 2009, Hydro-Québec Distribution's Interruptible Load Program (totaling 564 MW) was called two hours ahead of time due to a short-term load forecast increase.

During the 2009/2010 winter in Québec, there was no need for use of the following:

- Special Protection System or Remedial Action Scheme operations.
- Voltage reductions or public appeals
- Firm interchange transactions which were interrupted

However, at peak, 440 MW of non-firm transactions were interrupted for reliability purposes.

The fact that the Québec Balancing Authority area is strongly winter-peaking represents an operational challenge. This winter peaking characteristic is due to the very large amount of electrical space heating in Québec and morning load pick-up on colder days is challenging for System Control. Consequently, morning load pick-up coupled with interconnection ramping in export mode, may become an issue regarding voltage control. Large hydroelectric generation facilities are located in the northern portion of the province, whereas load is mostly located in the southern part of the province and energy must be transferred through long 735 kV lines to supply the load. The distance from Montréal (the largest load center) to the large generation facilities is in the order of 1,000 km (600 miles). Five interfaces along the system have operating limits that must be monitored at all times. The challenge is to minimize bottled generation over these interfaces and to supply the load while adequately controlling system voltages.

Another challenge is that TransÉnergie's system is a separate Interconnection from the Eastern Interconnection, to which the other NPCC Areas are interconnected. Frequency regulation is therefore a concern for the Area. The normal frequency profile is 59.5 to 60.5 Hz, and frequency excursions following a normal contingency may reach 58.5 to 61.5 Hz. Interconnections with other NPCC areas consist either of HVdc ties or radial generation to and from neighboring systems. Day-ahead and hour-ahead assessments are continually being used to maintain ACE and frequency within acceptable bounds in real-time.

Some unexpected conditions did occur during the Winter Operating Period. From January 3 to January 8, 2010, there was massive ice accumulation on lines 7004 (Micoua Laurentides) and 7019 (Micoua Saguenay) eventually causing their overhead ground wire to break and the lines to trip. The lines were out of service temporarily until the ground wires could be removed and the lines de-iced.

Another 735 kV line ☐ Line 7018 (Saguenay ☐ Jacques-Cartier) ☐ was out of service from January 7, 2010 to March 18, 2010. This line also suffered an ice storm and one tower collapsed completely. The remote location of the tower and adverse weather and terrain conditions explain the delay to get the line back in service. Impacts on the system were a transfer capability reduction of 500 MW on the Manicouagan ☐ Québec and Southern Interfaces throughout the Winter Operating Period. About 200 MW of generation was constrained due to this outage. No load was lost due to the line trip nor was any load impacted for the duration of this outage.

Reliability Assessment Analysis

The Québec Balancing Authority assesses its operating reserve in accordance with NPCC's A-06 Document "Operating Reserve Criteria."²⁵ Thus, the Operating Reserve Requirement is the sum of the 10-minute and 30-minute reserves equal to the first contingency loss plus half of the second contingency loss of generation. The actual operating reserve at peak was 1,600 MW at 18h00 EST on January 29, 2010. The Operating Reserve Margin is the difference between the Operating Reserve and the Operating Reserve Requirement (OPR). The OPR is calculated each minute in real-time and is based

²⁵ <http://www.npcc.org/viewDoc.aspx?name=A-06.pdf&cat=regStandCriteria>

on the most severe single contingency, which was, at the time of peak, the loss of a transformer at Churchill Falls integrating 1,023 MW of generation. The operating reserve was close to the 1,535 MW OPR threshold before 18h00 at the time of peak due to high load. A reduction of scheduled exports beginning at 18h00 with load starting to drop back after peak time caused the operating reserve to recover quickly.

TransÉnergie's Post Seasonal Assessment is presently ongoing. To date, no system issues or conditions, other than those discussed in this report (line outages due to weather conditions) have been highlighted for the winter period. In TransÉnergie's Peak Load Assessment, about 1,520 MW of hydraulic restrictions and generation outages were forecasted. At peak time, actual restrictions and outages totaled 2,375 MW. However, this had no impact on reliability since other resources were available through Demand Response programs, energy and capacity contracts with other systems in Québec and import/export modulation from/to the Balancing Authority area.

The Winter Operating Period was, as a whole, relatively quiet due to warmer than normal weather. Other than what was discussed above, no other extreme weather conditions and no major outages affected the system. As mentioned above, the outage of Lines 3089 and 3090, on two occasions caused, Hydro-Québec load to be transferred to New Brunswick for a total of 12 days. In the first instance, the load transfer lasted almost 11 hours. There was a disconnect switch problem which was solved. However, due to operating procedure improvements, the final load transfer back to Hydro-Québec on January 12, 2010 actually lasted only 8 minutes on average. This improvement was certainly a positive experience for both TransÉnergie and the New Brunswick System Operator.

SaskPower Reliability Coordinator

The Saskatchewan Power Corporation (SaskPower) is a provincial Crown corporation and operates under the legislated mandate and authority of the provincial government of Saskatchewan. SaskPower is the principal supplier of electricity in the province of Saskatchewan, and its obligation is to deliver power in a safe, reliable, and sustainable manner to the province. SaskPower is the sole Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Service Provider, Planning Coordinator, Transmission Planner, Resource Planner, and Load Serving Entity for the province of Saskatchewan.

Demand

The peak demand values presented in this report are for the Saskatchewan Power Corporation Reliability Coordinator. An hourly peak demand of 3,147 MW or instantaneous peak demand 3,214 MW was reported to the MRO for the Winter Seasonal Assessment. The actual instantaneous peak demand of 3231 MW turned out to be 0.5 percent greater than the forecasted instantaneous peak demand.

The peak demand was realized at the end of a weeklong cold snap during which temperatures dipped nearly 20 degrees Celsius below seasonal average to -35^{degrees celsius}. Saskatchewan did not experience any extreme or prolonged weather conditions during the 2009/2010 winter season. There was no demand response called upon by the Reliability Coordinator during the time of the seasonal peak.

Generation

There were no delays to new initial operation for this season. There were no delays to existing units being brought back into service for the 2009/2010 winter season in Saskatchewan.

Transmission

There were no delays in achieving commercial operation of new transmission during the 2009/2010 winter season in Saskatchewan.

Operational Issues

There was no loss of firm load in Saskatchewan due to the non-performance of a bulk power system resource or due to bulk transmission outage. No fuel situations negatively impacted the use of resources. There were no Emergency Operating Procedures deployed and no use of Demand Response for reliability purposes as contingency reserves throughout the winter season.

During the peak, there were no Special Protection Systems (SPS) or Remedial Action Scheme (RAS) operations, voltage reductions or public appeals implemented. In addition, no interchange transactions, firm or non-firm, were interrupted during the peak.

The most important challenge operating the bulk power system in Saskatchewan is in the real time unit commitment process. Forecasting the amount of wind production to be utilized during the day is critical for the Balancing Authority operator to make the proper selection of units to commit.

Reliability Assessment Analysis

The actual operating reserve at time of peak was 368 MW. This number represents the total number of MW counted from both non-spinning and spinning units available in Saskatchewan at that time. At the time of this peak, Saskatchewan had 356 MW of spinning reserve on-line.

Saskatchewan's contingency reserve requirement is based on its largest single net unit contingency of 281 MW. The reserve requirement is based on the NERC reserve requirement BAL-002-0. Saskatchewan's spinning reserve requirement of 112 MW is based upon 40 percent of its largest net unit contingency. The 40 percent spinning reserve requirement is based on the MRO spinning reserve requirement MBAL-002-0.

The wind production at time of peak was an important contributor to meeting the peak load. Without the 147 MW (of 172 MW nameplate) of wind generation Saskatchewan operating reserves would have potentially been reduced to 221 MW. This would have left Saskatchewan 60 MW deficient of their 281 MW operating reserve required at the time of peak. However, there was no significant impact on reliability as imports or interruptible load was available in order to maintain operating reserve at required levels, if necessary.

Saskatchewan has learned through their experiences that it is important to plan each hour of the day in particular the next hour to ensure that there is enough capacity to meet any peak loads. Forecasting the amount of wind production to be used during the next hour is critical for the Balancing Authority operator to make the proper selection of units to commit.

SERC Reliability Coordinators

SERC Reliability Corporation serves as a Regional Entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. The SERC Region is divided geographically into five subregions/Reliability Coordinators that are identified as Central, Delta, Gateway, Southeastern, and VACAR.

The Post-Winter Reliability Assessment for the SERC Region showed adequate resources were available to serve the peak demand in the Region even taking into account the wide ranges of uncertainty regarding the economic and weather climates. The winter peak was reached in early January during a prolonged period of sub-freezing weather. Few issues occurred during the 2009/2010 winter period with no significant reliability concerns regarding bulk power system reliability.

Demand

The intent of the SERC 2009/2010 Post-Winter Reliability Assessment is to compare the actual state of the bulk power system for the SERC Region to forecast values reported by regional entities listed in the NERC 2009/2010 Winter Reliability Assessment published in November 2009. The non-coincident preliminary “actual” 2009/2010 winter peak demand for the utilities in the SERC Region was 168,937 MW. The total aggregate internal demand for the 2009/2010 winter was forecasted to be 162,886 MW; this is 6,051 MW (3.6 percent) lower than the preliminary “actual” 2009/2010 winter peak demand. In January 2010, colder than normal weather swept across the Region resulting in all-time winter peaking conditions and unusually high energy demand. Additionally, it is unknown at this time how much demand response was used at the time of peak; it was expected that approximately 5,200 MW would be available for use during the 2009/2010 winter season.

All numbers used in the demand and reliability assessment analysis sections of this report are based on the SERC Region, less the Dominion area within the VACAR subregion. The Dominion area is reported in the PJM section of the post-winter seasonal assessment.

Generation

Minor unit delays occurred during the 2009/2010 winter. Entities within the SERC Region reported a delay in the return of the Wilson unit following the scheduled outage that occurred from October through most of December. McIntosh units #1, #2 and #3 were to be unavailable for a portion of the winter due to control system problems following a planned maintenance event. In order to minimize concerns with delays, the entities within the SERC Region planned for the season with the possibility of these events by making several firm capacity purchases to compensate for this capacity. Entities did not experience any reliability concerns due to unit delays. Any delay in unit initial operation or in a return to operation is communicated from the Generator Owner/Operators to the Transmission Operators and Balancing Authority to allow mitigation procedures to be developed and employed when needed.

Transmission

Entities did not experience any significant delays to the commercial operation of new bulk electric transmission lines during the 2009/2010 winter season that impacted reliability to the bulk power system.

Operational Issues

Although some entities within the region set new all-time winter peaks for the 2009/2010 operating season due to a prolonged period of sub-freezing temperatures in January 2010, no emergency imports were needed other than those that qualify for reserve sharing. The normal procedure for members within the Southwest Power Pool Reserve Sharing Group is that when members of the group need import assistance, the energy is delivered pursuant to the emergency energy schedules of the interconnection agreements between members. During the 2009/2010 winter season, assistance was scheduled from the group during December 2009 due to the forced outage of Arkansas Nuclear One Unit #2 and in January 2010 due to the forced outage of Independence Steam Electric Station Unit #2.

Entities did not experience losses of firm load due to the non-performance of a bulk power system resource or due to bulk transmission outage(s) during the 2009/2010 winter season.

Utilities within the Region began the winter season with adequate inventory levels and a diversified portfolio of coal suppliers. High-sulfur coal is purchased from different coal mining regions and moved between plants. These practices allow companies the ability to avoid interruptions. Because of their planning in this area, there were no significant fuel situations impacting the use of resources during this time period.

During the winter season, entities implemented winterization procedures/checklists at various plants. There were also some curtailments of transmission schedules to meet generation deficiencies. However, no abnormal emergency operating procedures were deployed during the season to maintain reliability.

Most entities within the Region do not use demand response resources during the winter season. However, some entities did report calling on industrial customer interruptible demand during the month of January 2010, as permitted through service agreements. Programs such as 6 hour, 2.5 hour, and 1.5-hour curtailable customers were called upon for projected generation/reserve shortfalls in the Amite-South load pocket due to very low temperatures, high loads, unscheduled/scheduled native-load generation loss, and requested generation re-dispatch for system reliability. During the 2009/2010 winter, approximately 4,180 MW of contractually interruptible load was projected to be available within the Region.

In addition, there were no Special Protection Systems (SPS) or Remedial Action Scheme (RAS) operations during the 2009/2010 winter season. Entities within the SERC Region also did not implement any voltage reductions or public appeals during this time-period. However, various companies experienced periodic interruptions of non-firm imports and exports due to congestion on the transmission system or the interruption of resources supplying the non-firm product. Interruptions were also due to hourly economic purchases and/or sales, transmission constraints, inability to meet performance requirements and generation schedules. There were many instances of TLR activity at level 3a and above during the 2009/2010 winter season. For the winter peak, entities reported that there were no firm transaction curtailments. Overall, interruption of transactions did not jeopardize reliability on the system.

Entities within the Region reported that their operational challenges during the winter season were issues related to:

- loop flows due to loss of generation and external constraints from other systems,
- balancing authorities that impact import capability,
- lack of available transfer capability and congestion on the transmission system,
- natural gas pipeline restrictions,

- scheduling conflicts due to maintenance requirements and/or new construction, irregular usage of units due to regressing economic conditions and the reliability effects of extreme cold weather conditions

Some entities reported that the 2009 fall and 2009/2010 winter operating seasons brought about unusual changes in generation dispatch due to the volatility of fuel prices. However, with proactive operational planning studies and analysis along with the inherent operating flexibility of the system, these unusual dispatch patterns were managed without degrading the reliability of the bulk power system.

Reliability Assessment Analysis

The aggregate preliminary “actual” 2009/2010 winter operating reserve margin for the utilities in the SERC Region was 11.6 percent. Operating reserve margins are calculated by dividing the projected reserves (19,558 MW) by the forecasted peak demand (168,937 MW). SERC does not implement a regional or subregional reserve requirement. As described in more detail within previous subregional assessments, many utilities in the SERC Region adhere to their respective state commissions’ regulations or internal business practices regarding maintaining adequate resources. For example, a target margin is implemented by regulatory authorities in the state of Georgia, where the regulation is only applicable to the investor-owned utilities in that state. Based on a recent review of resource adequacy assessment practices, many utilities in the SERC Region use a probabilistic generation and load model to assess and determine that adequate resources are available and deliverable to the load. However, capacity resources were adequate to supply the projected firm winter demand.

Other than the events mentioned above, entities did not have any other significant system issues, that impacted reliability during the 2009/2010 winter season. From these experiences, entities will continue to monitor system conditions. In situations of prolonged periods of sub-freezing temperatures that result in unusually high-energy demand, entities will also continue to adequately address issues through existing processes and procedures for the system.

The analysis performed within the post-winter seasonal assessment was based on the information provided in the SERC morning reports, and reporting guidelines were established on a Reliability Coordinator basis. In order to better align with systems in place, the Dominion area of VACAR was reported by PJM. To adjust the data presented, an approximation may be made by applying a 10.5 percent increase to the SERC Region number. It is indeterminable whether the adjustment is enough given the high peak demands seen during the winter season.

Other Issues

To minimize reliability concerns within the Region, entities rely on a variety of procedures. Some activities such as monthly, weekly, and daily operational planning analyses, improvement of vegetation management procedure programs, preventative maintenance on units during the off-peak period, routine maintenance on transmission equipment and maintaining adequate reserves are examples of steps that utilities within SERC have implemented to maintain the reliability of the bulk power system. These steps show that entities are focused on mitigating risks and maintaining reliability.

Although some companies reached new all-time winter peaks during the 2009/2010 winter season, facilities performed well during the assessment period and continue to reduce reliability impacts across the system.

SPP Reliability Coordinator

The SPP Reliability Coordinator (RC) provides reliability coordination services throughout an area encompassing parts or all of nine states. Included in this footprint are 29 Balancing Authorities in the SPP, SERC and MRO regional entities.²⁶ Winters typically are mild in the southern portions of the footprint but can be challenging in the northern portions. The winter of 2009/2010 brought unseasonably cold temperatures for extended periods throughout the entire footprint. Severe weather, including significant ice and snowstorms, were experienced in several areas within the footprint. These storms resulted in appreciable loss of load and on one occasion the creation of two small islands. In spite of the weather, which also brought record winter demands, no significant operational issues were encountered outside of storm damage. Except for one EEA 3, which resulted from firm TLR curtailments, sufficient capacity and energy were available to serve the demand.

Demand

The SPP RC footprint experienced a peak demand of 41,578 MW on January 8, 2010. This value represents a non-coincident peak across the RC footprint that includes Balancing Authorities (BAs) in SPP, SERC and MRO. This compares favorably with the seasonal peak forecast of 40,306 MW. (Due to calculation errors, this forecasted value, as well as the daily forecasted peak demand, was reported incorrectly in our Daily Operations Reliability Report.) The actual peak compares even more favorably with the corrected, current day forecast on January 8, 2010 of 41,542 MW. The Seasonal Assessment peak forecast of 32,636 MW only accounted for the SPP RTO as indicated in the assessment. The vintage of the SPP RTO 2009/2010 winter peak demand forecast was August 2009 and the forecast was published in SPP's EIA Internal Report that was released in August 2009.

The 2009/2010 winter peak demand established a new all-time winter peak for the footprint exceeding the previous peak (37,694 MW) by almost 4,000 MW. In fact, daily peak loads in the SPP RC footprint exceeded the previous winter peak each day during the week of January 4th. Extremely cold temperatures, with highs below freezing, persisted throughout the footprint with central and southern Louisiana being the only portion of the footprint where temperatures were above 32°F on January 8, 2010. A wintery mix of precipitation was experienced off and on throughout the week even down into Louisiana. The all-time peak for the footprint, established on June 23, 2009, is 48,242 MW.

Appreciable demand response does not exist within the SPP RC footprint. Within the RTO only approximately 650 MW of demand response is in place. No actual demand response was used in the SPP region on January 8, 2010.

Generation

No reliability concerns resulted from delays associated with construction or maintenance schedules on generating units within the SPP RC footprint.

Transmission

Transmission improvements associated with the Iatan #2 Unit were scheduled to be completed this past winter in anticipation of the new Kansas City Power & Light unit coming online during the summer of

²⁶ Includes Nebraska members currently within the MRO Region.

2010. However, the facilities were not placed in service until March 15, 2010. The delay of these facilities may have contributed to four Level 5 TLR events in the area during the winter season. The use of TLR to control loading in this area in the past has been a frequent event. Occasional escalation to firm curtailments is not unusual.

Operational Issues

No loss of firm load occurred during the winter due to non-performance of generation nor were there any fuel issues that impacted that generation. No Emergency Operating Procedures were used to maintain reliability. Demand Response was not used to provide contingency reserves for reliability purposes.

On January 28, 2010, Oklahoma suffered a major ice storm impacting six BAs in the state. During a 6-day period, through February 2, a total of 31-138kV, 2-161kV, 1-230kV and 10-345kV line outages occurred. Over 70,000 customers experienced outages during this period. Two small islands were also created during this event. The first occurred on January 29 and was centered on AEP West's (CSWS) Southwest Power Station and included distribution load served out of the plant, a 69kV radial feed to a distribution substation and the plant auxiliary load. Total load in this island was approximately 15 MW. Due to loss of remote telemetry and outdated EMS displays and maps, this island was not discovered for almost 23 hours. The island was isolated at 1138 CDT on January 29 and was re-synchronized with the Eastern Interconnection at 2146 CDT on January 31. During storm restoration, a second island occurred at 1433 on February 1. This island also was centered on AEP West's Southwest Power Station and included WFEC's Anadarko Plant, which is one bus away from Southwest via a 138kV interconnection. Total load in this island was approximately 40 MW. The island was re-synchronized with the Eastern Interconnection at 1701 CDT on February 1.

Another weather related event occurred in Oklahoma on February 11-12, 2010. During this event up to 8 inches of snow fell in parts of southeastern Oklahoma and northeastern Texas resulting in slightly over 50,000 customer outages on in the AEP West BA. Although this was primarily a distribution event, 1-138kV and 2-69kV lines experienced outages during the two-day period.

Louisiana Energy & Power Authority (LEPA) requested a Level 3 Energy Emergency Alert (EEA 3) on January 11, 2010 in response to a firm transaction curtailment resulting from a Level 5 TLR issued by the ICTE RC (Independent Coordinator of Transmission – Entergy, Reliability Coordinator). LEPA normally purchases regulation service from CLECO utilizing firm transmission service. On the 11th, due to heavy system loading brought about by cold temperatures, the ICTE RC resorted to TLR to control loading. Escalation to a Level 5 TLR curtailed LEPA's regulation service. Due to high demand and TLR, LEPA was unable to purchase replacement power. All internal generation was on-line. The EEA was issued at 0705 CDT and terminated at 0809 CDT. LEPA's deficiency during the period was 45 MW.

On the day of the peak no Special Protection Systems (SPS) or Remedial Action Schemes (RAS) operated. There were no voltage reductions or public appeals for load reduction implemented. No firm interchange transactions were curtailed on the day of the peak. Non-firm interchange transactions representing approximately 12,500 MWh of energy were curtailed during 17 TLRs on 11 flowgates on the day of the peak. These curtailments were in support of congestion management across the SPP RC footprint.

Integration of intermittent resources continues to be a significant challenge within the SPP RC footprint. The SPP RTO Wind Integration Task Force recently submitted its final report. Results include a

determination that the RTO can absorb wind penetration levels of up to 20%; however, significant transmission improvements and forecasting tools are required to support that density. To that end, a project is currently underway to obtain and implement a region-wide wind-forecasting tool.

Reliability Assessment Analysis

On the day of the winter peak, the SPP Reserve Sharing Group (RSG) operating reserve requirement was 1,878 MW. Of this amount 1,089 MW was allocated to BAs within the SPP RC footprint. The remainder was assigned to other BAs outside the footprint. Actual reserves available that day totaled 4,803 MW for the RSG of which 2,338 MW were available within the SPP RC footprint. The daily operating reserve requirement for the RSG is set at 100 percent of the capacity of the largest generating unit plus 50% of the capacity of the next largest generating unit scheduled to be on-line for that day. This requirement is allocated to the RSG members based on their pro rata share of the entire RSG firm load obligation for the previous day. Simply stated - tomorrow's reserve requirements are calculated today based on yesterday's peak load. The daily operating reserve requirement provides adequate coverage for the most severe single contingency within the RSG.

The single most challenging condition that impacted operations within the SPP RC footprint this past winter was the weather. While winter conditions typically are not that much of an issue across the entire footprint, localized weather conditions from time to time can cause problems. Ice storms and blizzards can create operating situations, which must be addressed in order to reliably serve the load. This past winter those sometimes extreme, localized conditions were felt throughout the entire RC footprint. Load was up significantly but did not create any insurmountable issues. Overall, generating capacity was available to serve the load and loading on the transmission system did not restrict the delivery of that generation to the load.

WECC Reliability Coordinator

WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western states in between. Due to the vast and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles.

For this assessment, WECC is divided into four areas: Northwest Power Pool Reserve Sharing Group (NWPP RSG), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSR), and California/Mexico (CA/MX). It should be noted that the geographic boundaries for two of the four areas differ from the geographic boundaries for the WECC subregions as the Northwest Power Pool Reserve Sharing group includes the Sacramento Municipal Utility District and Turlock Irrigation District Balancing Authorities. Those Balancing Authorities are included in the California/Mexico – U.S. Systems subregion in WECC's pre-winter and long-term reliability assessments.

Demand

The peak demand, reserve, and outage values presented in this assessment are based on non-coincident data extracted from WECC's *NERC Situational Awareness Morning Report* and from the *WECC Interconnection Daily Status Report* that is posted Monday through Friday, except holidays, on WECC's Web site.²⁷ The non-coincident data values in those reports are presented for the four areas described in the Introduction section, and for WECC as a single entity.

WECC's 2009/2010 winter non-coincident peak demand of 128,461 MW occurred on December 8, 2009. There were no reported demand response activations at that time of peak demand. The following table presents WECC and reporting area winter peak demand information, including comparisons with same-day forecasts and pre-winter assessment forecasts. The pre-season forecasts presented in the table reflect an assumed normal weather condition while the same-day forecasts and actual peak demands reflect expected and actual weather conditions, respectively. Hence, the pre-season forecast deviations presented in the table may largely represent weather-driven variances.

The weather conditions experienced in WECC during peak conditions are aptly described in the National Agricultural Statistics Service, Agricultural Statistics Board, U.S. Department of Agriculture's Weekly Weather and Crop Bulletin release of December 15, 2009²⁸.

²⁷ [WECC Interconnection Daily Status Report](#)

²⁸ <http://usda.mannlib.cornell.edu/usda/nass/WWNatSumm/2000s/2009/WWNatSumm-12-15-2009.pdf>

Table WECC – 1: Non-Coincident Peak Demands

Area	NWPP RSG	SRSG	RMRG	CA/MX	WECC
Date	12-8-09	12-10-09	12-9-09	12-8-09	12-8-09
Actual Peak Demand ²⁹	63,231	16,568	10,261	38,831	128,621
Same-Day Forecast	62,433	15,994	9,914	37,728	125,665
Forecast Deviation	1.3 %	3.6 %	3.5 %	2.9 %	2.4 %
Pre-Season Forecasts					
December	65,154	18,564	9,859	40,287	133,864
Forecast Deviation	-3.0 %	-10.8 %	4.1 %	-3.6 %	-3.9 %
Winter	65,154	18,880	9,859	40,287	133,864
Forecast Deviation	-3.0 %	-12.2 %	4.1 %	-3.6 %	-3.9 %

Generation

WECC did not experience reliability concerns due to either new plants not entering service as scheduled or existing units being brought back into service late after scheduled outages. The largest delayed addition was the 750 MW Comanche 3 coal-fired power plant in Colorado. In California, the 365 MW second unit of the Inland Empire Energy Center gas-fired power plant did not enter service during the winter period. In Arizona, the 400 MW Springerville unit 4 coal-fired plant entered service during the winter period.

Transmission

WECC did not experience reliability concerns due to new transmission not entering service as scheduled.

Operational Issues

WECC experienced several events during the winter period that resulted in the issuance of an *Electric Emergency Incident and Disturbance Report* (Department of Energy Form OE-417). Year-to-date summaries of the incidences are available on the U.S. Energy Information Administration's website³⁰. Two of the three WECC incidences for December involved the issuance of public appeals for energy conservation while the third incidence related to widespread distribution system outages caused by severe winter weather in northern Arizona. The OE-417 report for that incidence noted that up to 140,000 customers were affected by weather-related outages but there were no reported firm load curtailments related to bulk power system problems during the December through February winter period.

WECC prepared preliminary disturbance reports for one event in December and one event in February. On December 21, the Cranbrook-Selkirk 500-kV line between Alberta and British Columbia tripped and a normal remedial action operated to separate Alberta from the Western Interconnection. The interconnection line flow of 240 MW was disrupted for about 18 minutes. No generation was dropped and no other facilities or customers were affected. On February 17, the Ravenswood-Palo Alto #1 and #2 and the Palo Alto-Cooley Landing 115-kV lines in California tripped, interrupting service to approximately 28,000 customers (117 MW of demand). Customer service was restored in about 10

²⁹ "Actual" values reflect data that has not been adjusted based on updated/revised data (e.g., meter error adjustments).

³⁰ <http://www.eia.doe.gov/cneaf/electricity/epm/tableb2.html> and
<http://www.eia.doe.gov/cneaf/electricity/epm/tableb1.html>

hours and 20 minutes. A small aircraft flying into a transmission line tower was cited as the cause of the outage. There were no other reports describing loss of firm load due to bulk transmission system outages and there were no reports describing unexpected fuel situations that adversely impacted the use of resources.

Other than reserve sharing activations, no emergency operating procedure implementations were reported to maintain reliability, nor were there any reports of demand response being deployed for reliability purposes as contingency reserves. No special protection system or remedial action scheme actions were reported during WECC peak demand periods. There were no reported voltage reductions implemented in the areas during peak demands periods, nor were there any reported firm or non-firm interchange transactions that were interrupted.

A few public appeals (Level 1 Energy Emergency Alerts) were issued during the early December cold snap that engulfed the Western Interconnection. In addition, on December 8, the PacifiCorp East balancing authority requested issuance of a Level 2 Energy Emergency Alert due to loss of 375 MW of internal generation. The deployment of contingency reserve obligation and activation of Northwest Power Pool reserve sharing resulted in recovery from the generation loss in four minutes. System reserves were restored to required levels within less than an hour and the alert was canceled.

Reliability Assessment Analysis

The required and actual operating reserves at time of peak demand are presented in the following table.

Area	NWPP RSG	SRSG	RMRG	CA/MX	WECC
Date	12-8-09	12-10-09	12-9-09	12-8-09	12-8-09
Forecasted Operating Reserve	6,714	2,270	1,050	4,304	14,192
Required Operating Reserve	4,370	1,120	690	2,641	8,802
Actual Reserve	12,120	3,650	1,533	3,613	20,203
Margins					
Actual Peak Demand	63,231	16,568	10,261	38,831	128,621
Reserve Margin - %	19.2 %	22.0 %	14.9 %	9.3 %	15.7 %

The above tabulated actual non-coincident reserve margins at time of peak demand of roughly 9 to 22 percent exceeded WECC's minimum reserve requirement, which is generally less than seven (7) percent of firm peak demand. WECC's operating reserve requirement is calculated in accordance with WECC Standard BAL-STD-002-0³¹. The WECC reserve sharing groups and CA/MX Balancing Authorities are obligated to meet the minimum standard, but each may consider additional intra-area factors that result in the calculation of a higher margin requirement.

Other Issues

In addition to the events discussed previously, WECC experienced noteworthy post-peak demand storm-related conditions in California. A synopsis of those events, as presented in the U.S. Energy Information

³¹ [Standard BAL-STD-002-0](#)

Administration’s *Electric Power Monthly – Major Disturbances and Unusual Occurrences*³² Summary for January 2010, follows:

- On January 18, a major storm with high winds and rainfall hit a significant portion of northern and central California. The resulting load loss was 290 MW with 1.7 million customers affected.
- On January 19, an additional 300 MW of demand was lost affecting 30,000 customers in the San Francisco area due to severe weather.
- On January 19, San Diego and Orange Counties experienced 2,650 MW of service interruptions to 50,000 customers due to severe weather.
- On January 20, the city of Los Angeles experienced service interruptions to 147,223 customers (cumulative through the 24th) due to severe weather.
- The Friday Evening, January 22, 2010 issue of Energy Assurance Daily, published by the U.S. Department of Energy’s Office of Electricity Delivery and Energy Reliability – Infrastructure Security and Energy Restoration, reported on several storm-related distribution system outages in WECC as follows:

According to the latest information available, some 67,200 customers are without power across California as storms caused new outages across the state on January 21-22, sources reported. The storms cut power, in total, to more than 1.3 million Pacific Gas & Electric (PG&E) customers, 317,924 Southern California Edison (SCE) customers and more than 150,000 San Diego Gas & Electric (SDG&E) customers, but to no more than 165,000 PG&E customers, 53,397 SCE customers and 70,000 SDG&E customers at one time, according to sources. While Governor Schwarzenegger was in Washington D.C., Acting Governor Jerry Brown declared a State of Emergency for four counties, citing the storms, mudslides and related factors. Later on return to the state, Schwarzenegger declared a state of emergency for an additional county and said 82,000 residents were still in the dark, but those numbers were difficult to confirm, based on news and utility sources.

California Customer Power Outages January 18-22, 2010			
Electric Utility	State	Peak	Latest Reported
Pacific Gas & Electric	CA	165,000	43,000
San Diego Gas & Electric	CA	70,000	1,400
Southern California Edison	CA	53,397	13,835
Sacramento Municipal Utility District	CA	50,000	1,645
LADWP	CA	10,000	2,600
Pacific Power	CA	8,900	4,720
TOTAL*		357,297	67,200

*Total outages only represent electric utilities listed in this table.

³² <http://www.eia.doe.gov/cneaf/electricity/epm/tableb1.html>

About This Report

The *2009/2010 Post-Winter Operational Reliability Assessment* represents NERC’s independent judgment of the performance of the bulk power system in North America for the previous 2009/2010 winter season (Table A).³³ The report specifically provides a high-level reliability assessment of 2009/2010 winter resource adequacy and operating reliability, an overview of significant events, Regional highlights, and Regional self-assessments.

NERC’s primary objective in providing this assessment is to identify areas of concern regarding the reliability of the North American bulk power system and to make recommendations for their remedy as needed. The purpose of the Post-Seasonal Operational Reliability Assessment is for NERC and its stakeholders to document the challenges faced in the previous season, to assess Regional seasonal reliability preparations documented in the current Seasonal Assessments (Summer and Winter) compared to the actual conditions experienced during prior peaking season and provide a basis for lessons learned. This report is focused on a post-seasonal assessment, rather than traditional planning reports produced by the Reliability Assessment Subcommittee. The goal of this report is to assess planned operating/mitigation strategy implementation, document new strategies developed during the season, document actual operational experiences and share lessons learned.

Table A: NERC’s Annual Assessments		
Assessment	Outlook	Publish Target
Summer	Upcoming season	May
Post-Summer	Previous season	November
Long-Term Assessment	10 year	October
Winter	Upcoming season	November
Post-Winter	Previous season	May

Report Preparation

NERC prepared the *2009/2010 Post-Winter Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The report is based on data and information submitted by each of the eight Regional Entities on daily basis, except weekends and holidays, through the *NERC/FERC Morning Reports*.

NERC staff performed detailed data checking on the reference information received by the Regions. NERC also uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject matter expertise from many sectors of the industry. This process also provides an essential check and balance for ensuring the validity of the information provided by the Regional Entities.

³³Bulk power system reliability, as defined in the *How NERC Defines Bulk Power System 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.

References

Please refer to the documents below for abbreviations and terms used in this report.

2009/2010 Winter Reliability Assessment, November 24, 2009

http://www.nerc.com/docs/pc/ras/2010PostWinter%20Letter%20042810_Updated%20%28%29.pdf

Glossary of Terms Used in Reliability Standards, Updated April 20, 2010

http://www.nerc.com/docs/standards/rs/Glossary_of_Terms_2010April20.pdf

Reliability Assessments Guidebook, Version 1.2, March 18, 2008

http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf

Reliability Standards for the Bulk Electric Systems in North America, Updated May 20, 2009

http://www.nerc.com/files/Reliability_Standards_Complete_Set_2009May20.pdf

Self-Assessment Request for NERC Post-Winter Operational Reliability, Updated April 28, 2009

http://www.nerc.com/docs/pc/ras/2010PostWinter%20Letter%20042810_Updated%20%28%29.pdf

Reliability Assessment Subcommittee Roster

Chair	Mark J. Kuras Senior Engineer	PJM Interconnection, L.L.C. 955 Jefferson Ave Valley Forge Corporate Center Norristown, Pennsylvania 19403	610-666-8924 610-666-4779 Fx kuras@pjm.com
--------------	----------------------------------	---	---

Regional Entity Representatives — Members of the *Electric Reliability Organization: Reliability Assessment and Performance Analysis Group* (ERO-RAPA Group)

Vice Chair, FRCC	Vince Ordax Manager of Planning	Florida Reliability Coordinating Council 1408 N. Westshore Blvd Tampa, Florida 33607	813-207-7988 813-289-5646 Fx vordax@frcc.com
MRO	John Seidel Senior Manager, Operations	Midwest Reliability Organization 2774 Cleveland Avenue N Roseville, Minnesota 55113	651-855-1716 651-855-1712 Fx ja.seidel@midwestreliability.org
NPCC	John G. Mosier, Jr. AVP-System Operations	Northeast Power Coordinating Council, Inc. 1040 Avenue of the Americas-10th floor New York, New York 10018	212-840-4907 212-302-2782 Fx jmosier@npcc.org
RFC	Jeffrey Mitchell, P.E. Director, Engineering	ReliabilityFirst Corporation 320 Springside Dr. Suite 300 Akron, Ohio 44333	330-247-3043 330-456-3648 Fx jeff.mitchell@rfirst.org
SERC	Herbert Schrayshuen Director, Reliability Assessment	SERC Reliability Corporation 2815 Coliseum Centre Drive Charlotte, North Carolina 28217	704-940-8223 315-439-1390 Fx hschrayshuen@serc1.org
SPP	David Kelley Manager, Engineering Administration	Southwest Power Pool 415 N. McKinley Suite 140 Little Rock, Arkansas 72205	501-688-1671 501-821-3245 Fx dkelley@spp.org
TRE	William C. Crews, P.E. Regional Planning Assessment Engineer, Sr.	Texas Reliability Entity 2700 Via Fortuna Suite 225 Austin, Texas 78746	512-583-4989 curtis.crews@texasre.org
WECC	David J. Godfrey Director, Standards Development and Planning Services	Western Electricity Coordinating Council 155 North 400 West, Suite 200 Salt Lake City, Utah 84103	801-883-6863 801-582-3918 Fx dgodfrey@wecc.biz

TRE, ISO/RTO	Dan M. Woodfin Director, System Planning	Electric Reliability Council of Texas, Inc. 2705 West Lake Dr. Taylor, Texas 76574	512-248-3115 512-248-4235 Fx dwoodfin@ercot.com
MRO	Hoa V. Nguyen Resource Planning Coordinator	Montana-Dakota Utilities Co. 400 North 4th Street Bismarck, North Dakota 58501	701-222-7656 701-222-7872 Fx hoa.nguyen@mdu.com
ISO/RTO	Peter Wong Manager, Resource Adequacy	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040- 2841	413-535-4172 413-540-4203 Fx pwong@iso-ne.com
RFC	Evan R. Wilcox, PE Manager, Transmission Interstate Planning	American Electric Power 700 Morrison Rd. Gahanna, OH 43230	614- 552-1648 erwilcox@aep.com
RFC, IOU	Esam A. F. Khadr Manager - Delivery Planning	Public Service Electric and Gas Co. 80 Park PlazaT-14A Newark, New Jersey 07102	973-430-6731 973-622-1986 Fx Esam.Khadr@pseg.com
SERC	Hubert C. Young Manager of Transmission Planning	South Carolina Electric & Gas Co. 220 Operations Way MC J37 Cayce, South Carolina 29033	803-217-2030 803-933-7264 Fx cyoung@scana.com
SERC, IOU, DCWG Chair	K. R. Chakravarthi Manager, Interconnection and Special Studies	Southern Company Services, Inc. Southern Company Services, Birmingham, Alabama 35203	205-257-6125 205-257-1040 Fx krchakra@southernco.com
WECC, State/ Municipal Utility	James Leigh-Kendall Manager, Reliability Compliance and Coordination	Sacramento Municipal Utility District 6002 S Street b303 Sacramento, California 95852	916-732-5357 916-732-7527 Fx jleigh@smud.org
ISO/RTO	Jameson T. Smith Manager, Regulatory Studies	Midwest ISO, Inc. 1125 Energy Park Drive St. Paul, Minnesota 55108	651-632-8411 651-632-8417 Fx itsmith@midwestiso.org
ISO/RTO	John Lawhorn, P.E. Director, Regulatory and Economic Standards Transmission Asset Management	Midwest ISO, Inc. 1125 Energy Park Drive St. Paul, Minnesota 55108	651-632-8479 651-632-8417 Fx jlawhorn@midwestiso.org
FERC	Sedina Eric Electrical Engineer	Federal Energy Regulatory Commission 888 First Street, NE, 92-77	202-502-6441 202-219-1274 Fx sedina.eric@ferc.gov

RFC, LFWG Chair	Bob Mariotti Supervisor – Short Term Forecasting	Washington, D.C. 20426 DTE Energy 2000 Second Avenue 787WCB Detroit, Michigan 48226-1279	313-235-6057 313-235-9583 Fx mariottir@dteenergy.com
FRCC Alternate	John Odom, Jr. Vice President of Planning and Operations	Florida Reliability Coordinating Council 1408 N. Westshore Blvd., Suite 1002 Tampa, Florida 33607-4512	813-207-7985 813-289-5646 Fx jodom@frcc.com
MRO Alternate	Salva R. Andiappan Manager – Reliability Assessment and Performance Analysis	Midwest Reliability Organization 2774 Cleveland Avenue N. Roseville, Minnesota 55113	651-855-1719 651-855-1712 Fx sr.andiappan@midwestreliability.org
RFC Alternate	Paul Kure Senior Consultant, Resources	ReliabilityFirst Corporation 320 Springside Drive Suite 300 Akron, Ohio 44333	330-247-3057 330-456-3648 Fx paul.kure@rfirst.org
SPP Alternate	Alan C Wahlstrom Lead Engineer, Compliance	16101 La Grande Dr. Suite 103 Littlerock, Arkansas 72223	501-688-1624 501-664-6923 Fx awahlstrom@spp.org
WECC Alternate	Richard H. Simons Staff Engineer	Western Electricity Coordinating Council 155 North 400 West, Suite 200 Salt Lake City, Utah 84103	801-883-6880 801-582-3918 Fx dick@wecc.biz
OC Liaison	Jerry Rust President	Northwest Power Pool Corporation 7505 NE Ambassador Place, St R Portland, Oregon 97035	503-445-1074 503-445-1070 Fx jerry@nwpp.org
OC Liaison	James Useldinger Manager, T&D System Operations	Kansas City Power & Light Co. PO Box 418679 Kansas City, Missouri 64141	816-654-1212 816-654-1189 Fx jim.useldinger@kcpl.com
Observer DOE	Patricia Hoffman Acting Director Research and Development	Department of Energy 1000 Independence Avenue SW 6e-069 Washington, D.C. 20045	202-586-1411 patricia.hoffman@hq.doe.gov
Observer DOE	Peter Balash Senior Economist	U.S. Department of Energy 626 Cochrans Mill Road P.O. Box 10940 Pittsburgh, Pennsylvania 15236	412-386-5753 412-386-5917 Fx balash@netl.doe.gov
Observer DOE	Erik Paul Shuster Engineer	U.S. Department of Energy 626 Cochrans Mill Road P.O. Box 10940	412-386-4104 erik.shuster@netl.doe.gov

Pittsburgh, Pennsylvania 15236

Observer DOE	Maria A. Hanley Program Analyst	Department of Energy 626 Cochran Mill Road MS922-342C P.O. Box 10940 Pittsburgh, Pennsylvania 15236	412-386-5373 412-386-5917 Fx maria.hanley@netl.doe.gov
Observer	C. Richard Bozek Director, Environmental Policy	Edison Electric Institute 701 Pennsylvania Avenue, NW Washington, D.C. 20004	202-508-5641 rbozek@eei.org
Observer	Erick Hasegawa Engineer	Midwest ISO, Inc. Carmel Office PO Box 4202 Carmel, Indiana 46082	317-910-8626 ehasegawa@midwestiso.org

North American Electric Reliability Corporation Staff

Mark G. Lauby	Director of Reliability Assessment and Performance Analysis	mark.lauby@nerc.net
Eric Rollison	Engineer, Reliability Assessment and Performance Analysis	eric.rollison@nerc.net
John Moura	Technical Analyst, Reliability Assessment and Performance Analysis	john.moura@nerc.net