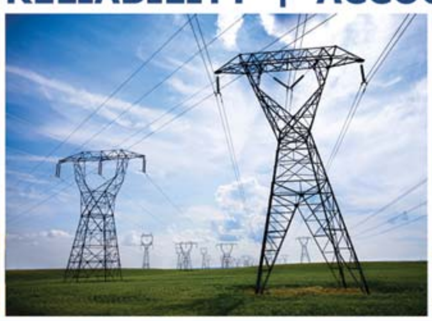
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2010/2011 Post-Winter Reliability Assessment

September 2011

RELIABILITY | ACCOUNTABILITY



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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 Reliability*First* 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.

Post-Winter Reliability Assessment Summary

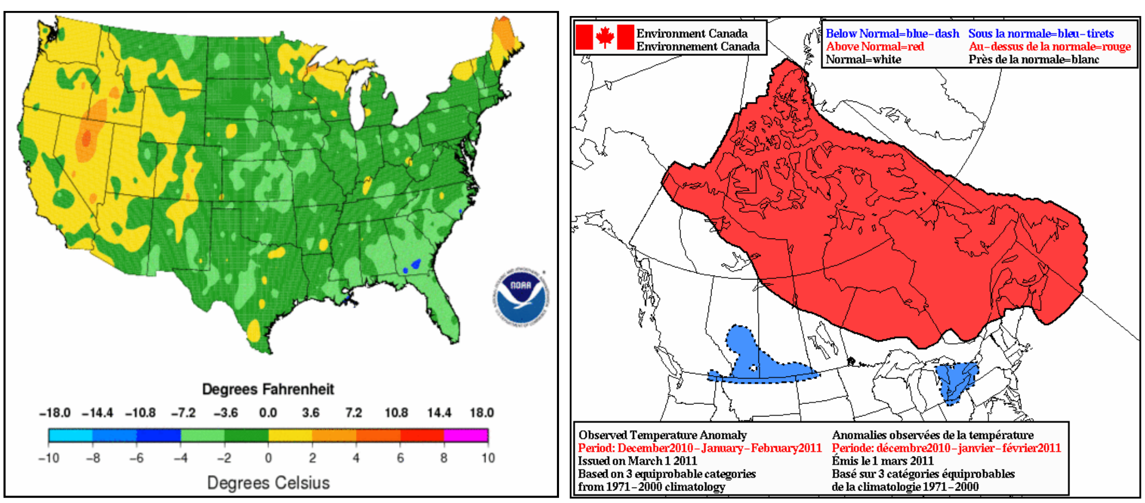
Overview

During the 2010/2011 winter, system operators across the NERC Regions maintained bulk power system reliability. Although ERCOT experienced extreme weather conditions in February that resulted in several plant shutdowns and an all-time winter season peak for the Region, operational procedures were executed in a manner that adequately balanced available generation while minimizing adverse consequences.

Demand

Day-ahead and seasonal forecasted peak demands exceeded actual forecasted peak demands in many Assessment Areas (see Table 1 and Table 2). Nearly all areas experienced peaks during either December or January. As seen in Figure 1, much of the country experienced below normal temperatures. Severe cold spells were experienced by all NPCC subregions at some point during either December or January; however, no significant challenges were reported in meeting peak demands. A new all-time internal peak demand was established for the Québec Interconnection. SERC entities also experienced below-average temperatures with severe storms in the Central area; however, no all-time winter peaks were reported in the Region. The SPP RC experienced a higher peak demand compared to the seasonal forecast and extreme winter weather resulted in loss or limitation of 5,925 MW of capacity due to frozen components. The PJM RTO, WECC, and SaskPower Areas all experienced near normal weather during the 2010/2011 winter.

Figure 1: Minimum Temperature Anomaly December 2010 - February 2011 (based on 1971-2000 Mean)[2],[3]



[2] NOAA Temperature Maps December 2010 - February 2011
http://www.ncdc.noaa.gov/temp-and-precip/maps.php?ts=3&year=2011&month=2&imgs%5B%5D=Statewidetrank&submitted=Submit

[3] Environment Canada Temperature Maps December 2010 - February 2011
http://www.weatheroffice.gc.ca/saisons/charts_e.html?season=djf&year=2010&type=t

Table 1: Day-Ahead vs. Actual Peak Demand

Assessment Area	2010/2011 Actual Winter Peak Demand (MW)	Day-Ahead Peak Demand Forecast (MW)	Difference between Actual and Day-Ahead Forecast (MW)	(%)	Winter 2010/2011 Month of Peak Demand
ERCOT	57,282	59,859	-2,577	-4.50%	February
FRCC	46,220	49,252	-3,032	-6.16%	December
MISO	97,355	97,777	-422	-0.43%	December
NPCC	111,522	110,185	1,337	1.21%	January
ISO-NE	21,166	21,900	-734	-3.35%	January
Maritimes	5,252	5,470	-218	-3.99%	January
NYISO	24,654	23,878	776	3.25%	December
Ontario	22,733	21,140	1,593	7.54%	January
Québec	37,717	37,797	-80	-0.21%	January
PJM	115,807	115,982	-175	-0.15%	December
SaskPower	3,203	2,880	323	11.22%	January
SERC	172,291	170,002	2,289	1.35%	December
Central	42,431	40,962	1,469	3.59%	December
Delta	23,820	25,576	-1,756	-6.87%	December
Gateway	15,020	15,339	-319	-2.08%	December
Southeastern	47,762	44,933	2,829	6.30%	December
VACAR	43,258	43,192	66	0.15%	December
SPP	41,076	39,660	1,416	3.57%	January
WECC	125,585	121,126	4,459	3.68%	January
CA-MX	37,664	36,503	1,161	3.18%	December
NWPP RSG	62,639	61,544	1,095	1.78%	January
RMRG	10,628	9,844	784	7.96%	February
SRSG	18,652	17,931	721	4.02%	February

Table 2: Seasonal Forecast vs. Actual Peak Demand				
Assessment Area	2010/2011 Actual Winter Peak Demand (MW)	Seasonal Peak Demand Forecast (MW)	Difference between Actual and Seasonal Forecast (MW)	(%)
ERCOT	57,282	48,066	9,216	19.17%
FRCC	46,220	46,235	-15	-0.03%
MISO	97,355	103,254	-5,899	-5.71%
NPCC	111,522	111,206	316	0.28%
ISO-NE	21,166	22,085	-919	-4.16%
Maritimes	5,252	5,616	-364	-6.48%
NYISO	24,654	24,289	365	1.50%
Ontario	22,733	22,271	462	2.08%
Québec	37,717	36,945	772	2.09%
PJM	115,807	114,776	1031	0.90%
SaskPower	3,203	3,304	-101	-3.06%
SERC	172,291	166,718	5,573	3.34%
Central	42,431	44,144	-1713	-3.88%
Delta	23,820	23,005	815	3.54%
Gateway	15,020	15,181	-161	-1.06%
Southeastern	47,762	42,473	5289	12.45%
VACAR	43,258	41,915	1,343	3.20%
SPP	41,076	40,554	522	1.29%
WECC	125,585	126,498	-913	-0.72%
CA-MX	37,664	38,836	-1,172	-3.02%
NWPP RSG	62,639	62,264	375	0.60%
RMRG	10,628	9,753	875	8.97%
SRSG	18,652	17,228	1,424	8.27%

Seasonal Experiences and Lessons Learned

Although each NERC Region is inherently different, many share similar operating challenges from season to season. Sharing these experiences and subsequent lessons learned with the industry can be helpful in developing solutions to mitigate or otherwise prevent future reliability issues. NERC will monitor these issues in subsequent reliability assessments. Lessons learned through the assessment of actual operating experiences may also be included in NERC's Event Analysis: Lessons Learned documents,[4] which can be targeted to specific stakeholders who may gain value from such information. Below are some of the experiences observed during the 2010/2011 winter.

Unplanned Outages of Transmission Lines

The FRCC Region experienced one Interconnection Reliability Operating Limit (IROL) exceedance condition on March 24, 2011, when a high-voltage line was out of service for planned maintenance. The SOCO and FRCC Reliability Coordinator convene through daily reliability calls with the Balancing Authorities, Transmission Operators, and the three gas pipeline operators (transporters) to discuss any reliability concerns within the Region. Typically, prior to and during the Advisory, the FRCC RC and the Operating Entities within its RC Area limit discretionary maintenance and ensure that all available transmission facilities are in service during the peak hours. Preparations are also made to mitigate issues resulting from the loss of high-voltage lines within the operating area. Proper communications between operating entities continue to be a leading method of effectively coordinating outages within affected and neighbouring areas.

Load Shed Management, Fuel Supply Issues, and Communication Policies

The ERCOT Region encountered significant challenges one week prior to the peak day of the 2010/2011 winter season. February had record-breaking winter demand levels on two different occasions as temperatures hit twenty-year lows in the ERCOT Region. On February 2, 2011, ERCOT experienced an EEA Level 3 event that led to the request to shed 4,000 MW of Firm load. An in-depth report on this event is available.[5]

Following ERCOT's challenge of managing the large and sudden impacts of unavailable generating units, the Region will work to further improve load shed management, fuel supply issues and communication procedures. Several enhancements and recommendations are discussed in the ERCOT section of this report.

Managing Large Quantities of Generation with Long Start-up-Time

ISO-NE faced the challenge of operating several fossil-based units with long start-up-times that require a high level of accuracy in forecasting both regional demand and cold weather unit availability. Extreme weather can augment these challenges and require additional oil-fired

[4] NERC Events Analysis: Lessons Learned (http://www.nerc.com/page.php?cid=5|385).

[5] http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

units to ensure reliability. ISO-NE has developed a Strategic Planning process to address this issue.

Operation during Severe Weather Conditions

During the January 2011, the Québec system reported a problem related to an interconnection transaction that prevented imports due to extreme cold temperatures that impeded the start-up of converters. Chateauguay procedures will be reviewed and updated.

A portion of the Western Interconnection power grid experienced significant operating issues during a cold spell that swept across the southwest and Texas. Subfreezing temperatures combined with the effects of severe wind chill resulted in the loss of several generation plants in the El Paso, Texas area. Subsequently, customers in the El Paso area experienced significant controlled, rotating outages. Unrelated plant outages in Arizona also resulted in firm load loss. WECC did not experience power supply problems due to the natural gas supply interruptions that mainly affected Texas, but certain plants in the Southwest did experience fuel curtailments. The peak demand of 125,585 MW occurred on January 11 and was 8.1 percent less than the all-time winter peak demand of 136,592 MW that occurred during December 2008.

In PJM, several ice storms also caused multiple cases of generator, transmission line, and substation outages. Although none of these outages caused any loss of load, some reports of distribution outages were reported on the DOE Form OE-417.[6]

[6] Electric Disturbance Events (OE-417) Annual Summaries (http://www.oe.netl.doe.gov/OE417_annual_summary.aspx).

ERCOT Reliability Coordinator

Demand

The ERCOT Region encountered significant challenges on one day during the 2010/2011 winter season, although not during the winter peak day. February had record-breaking winter demand levels on two different occasions as temperatures hit twenty-year lows. On February 2, 2011, ERCOT experienced an EEA Level 3 event that led to the request to shed 4,000 MW of Firm load. An in-depth report on this event by NERC and FERC was released in August 2011.[7]

A new all-time winter season preliminary peak demand of 57,282 MW was set during the following week on February 10, 2011 without encountering similar challenges. There were 6,284 MW of Operating Reserves available above this demand during the peak hour. With an available capacity of 62,870 MW during the winter peak on February 10, 2011, the Region had sufficient resources available to serve the winter's actual peak demand.

The preliminary actual coincident peak demand for the 2010/2011 winter period was 57,282 MW occurring on February 10, 2011 (hour-ending 08:00 CDT).[8] This peak was nineteen percent higher than the seasonal peak forecast of 48,066 MW,[9] based on normal peak weather conditions. This all-time winter peak demand exceeded the 2009/2010 winter season demand of 55,878 MW, but did not exceed the 2010 summer peak demand of 65,776 MW; ERCOT remains a summer peaking Region.

This peak demand was a result of abnormally low temperatures and wind chills throughout the Region, including areas in coastal and south Texas that do not normally experience sub-freezing conditions, as well as ice and snow in north Texas. No Demand Response activities were deployed for reliability purposes during the winter peak hour.

Generation and Transmission

The ERCOT Region had 62,870 MW of available capacity during the winter peak. The Region did not experience any reliability concerns during the 2010/2011 winter period for delays of new units scheduled for initial operations, for delays of existing units returning to service after a scheduled outage, or for delays of commercial operation of new transmission elements.

ERCOT experienced significant unavailability of resources due largely to freezing of instrumentation and sensing lines during the extreme weather events around February 2, 2011. Generation in the ERCOT Region is required to have weatherization plans. Most generation has been designed for performance during extreme hot summer seasons but their designs generally should have handled the low temperatures encountered. Over 150 generators faced difficulties

7 Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011.

8 Demand values calculated as a coincident peak and presented for the ERCOT Region as a whole.

9 NERC 2010/2011 Winter Reliability Assessment (http://www.nerc.com/files/2010_Winter_Assessment_V7_ERRATA.pdf).

handling the below freezing temperatures and high wind chills on February 2 and either were forced out of service, failed to start, or operated at a de-rated capacity. Evidently, many weatherization issues were immediately addressed, as this level of unavailability did not recur the following week during similar weather conditions resulting in the winter season peak on February 10, 2011. Aggregated wind output during the 2011 winter was 776 MW and curtailments totaled 53 MW for the peak hour occurring on February 10, 2011. Wind generation ranged between 500-3,000 MW during February 2-4, 2011 and contributed to reliability during the extreme weather events.

Operational Issues

On February 2, 2011, ERCOT declared an Energy Emergency Alert (EEA) Level 2A followed by a Level 3 at 05:43 (CDT) in response to frequency drops caused by generator forced outages, which occurred as below-freezing combined with low wind chill factors moved across the Region. The loss of generation caused the ERCOT Region to fall below its self-imposed Responsive Reserve minimum value of 2,300 MW and below the 1,354 MW minimum Contingency Reserve value for the ERCOT Region. As part of the EEA event ERCOT deployed 384 to 467 MW of Emergency Interruptible Load Service (EILS), 899 MW of Load Resources providing Responsive Reserve (885.9MW responded), and requested a total of 4,000 MW of Firm load shed throughout the entire ERCOT Region. The lowest frequency during the event was 59.576 Hz recorded at 06:05 (CDT) on February 2. Some Transmission Operators indicated that the available pool for Firm load shed was limited by other restrictions, such as under-voltage load shed (UVLS), under-frequency load shed (UFLS), and critical facility designation. The load shed achieved the necessary balancing with available generation and created limited adverse consequences. Firm load was restored by 01:07 (CDT) on February 2, 2011 with the exception of ERCOT’s Emergency Interruptible Loads and Load Resources providing Responsive Reserve Service. The EEA was cancelled at 10:00 (CDT) on February 3, 2011.

The February 2, 2011 EEA event was primarily caused by the unavailability of resources due to the freezing of instrumentation and sensing lines during extreme weather events. Generation in the ERCOT Region is required by the Public Utility Commission of Texas Substantive Rule §25.53[10] to have weatherization plans. Most generating units in the Region were designed for performance during extreme hot temperatures during the summers, but designs generally should have been able to handle the low temperatures encountered. Over 150 generators faced difficulties operating in the below-freezing temperatures combined with the high wind chills that occurred on February 2, 2011. Therefore, several plants either failed to start, were forced out of service, or operated at a derated capacity. As a result of these experiences, many weatherization issues were immediately addressed to prevent a recurrence the following week when similar weather conditions caused the Region’s seasonal peak on February 10, 2011.

[10] Public Utility Commission of Texas Substantive Rule; Chapter 25: Substantive Rules Applicable to Electric Service Providers; Subchapter C: Quality of Service; §25.53. Electric Service Emergency Operations Plans (http://www.puc.state.tx.us/agency/rulesnlaws/subrules/electric/25.53/25.53.pdf).

Temporary gas curtailments or supply equipment issues occurred at a limited number of units on February 2, 2011, but these issues were promptly remedied. ERCOT worked with state officials and received an emission waiver from February 2-5, 2011 to run critical plants needed to restore reliability.

ERCOT took the following preparations prior to the freezing temperatures on February 2 and February 11, 2011:

- Issued Operating Condition Notices to warn of approaching low temperatures;
- Dispatched one long start-up lead time generator, two days in advance;
- Dispatched one oil-burning generator, two days in advance;
- Withdrawal, cancellation, or delayed transmission outages scheduled to occur during the period;
- Procured 13 Generating Resources during the Reliability Unit Commitment process to address projected concerns of capacity and transmission congestion.

The required minimum Contingency Reserve[11] for the ERCOT Region is 1,354 MW, but the ERCOT Region plans for 2,300 MW of Responsive Reserve for all hours under normal conditions. ERCOT can increase the Responsive Reserve requirement during “extreme conditions.” On February 2, 2011, the ERCOT Region fell below the Regional Responsive Reserve minimum value of 2,300 MW for nearly eight hours. On February 2, 2011, the ERCOT Region fell below the 1,354 MW required minimum Contingency Reserve for over two hours. The lowest ERCOT Contingency Reserve level recorded was 447 MW at 06:25 (CDT) on February 2, 2011. Reserves were restored using load-shedding and concerted efforts to return generation to service or start additional units.

On February 3-4, 2011, ERCOT shed 400 MW of Firm load in the lower Rio Grande Valley area of the ERCOT Region. On February 3, 2011, the Valley area hit an all-time high winter peak load of 2,734 MW. The previous winter peak for the Valley area was 2,378 MW, set in 2010. Affected Transmission Operators implemented a limited operational load shed plan to avoid voltage collapse due to forced generator outages accompanied by record winter peak loads reported in the area. Restoration of generation facilities and a gradual increase in local temperatures discontinued the need for the load shed by 12:00 (CDT) on February 4, 2011. Public appeals were made on February 2-4, 2011; however, the impact on the Operating Reserve Margin was not quantified. There was no loss of Firm load due to transmission element outages during the 2010/2011 winter and no events occurred on the day of winter peak demand.

Special Protection Systems (SPS) did not operate during the 2010/2011 winter period to mitigate any reliability concerns. No voltage reductions were requested during the winter season for reliability concerns. Firm interchange transactions were not interrupted during the winter season that caused any reliability concerns; however, Non-Firm interchange transactions were interrupted during the winter season for reliability concerns in Mexico.

[11] As defined by NERC Standard BAL-002.

The forecasted Operating Reserves for the ERCOT Region during the peak period was 3,091 MW while the actual value was 6,284 MW, exceeding all reserve requirements. There were no other NERC-reportable Disturbance Control Standard (DCS) events or OE-417-reportable events during the winter period.

Seasonal Experiences and Lessons Learned

The most significant challenge during the 2010/2011 winter period was managing the sudden unavailability of large amounts of generation within a short time frame during high demand conditions on February 2, 2011. Multiple forced generator outages required swift action, including the deployment of Controllable Load resources and Emergency Interruptible Load Services combined with shedding Firm load to protect the integrity of the ERCOT grid. During the peak demand day of February 10, 2011, generator availability was significantly improved, which resulted in sufficient resources available to serve the peak demand while maintaining reserve requirements.

The ERCOT Region plans to complete the following action items, in response to the Energy Emergency Alert (EEA) event of February 2, 2011:

- **Power Plant Weatherization**: ERCOT will initiate and participate in discussions related to the adequate weatherization of generation units. This includes reviews of plant procedures, training programs for severe weather and winter weather events, and availability of resources in response to winter weather events. ERCOT held a Severe Weather Readiness Workshop[12] on June 8, 2011 to review the events of the 2010/2011 winter. During this event, executive management representing several large generators in the ERCOT Region gathered to share best practices in managing extreme weather events.
- **Load Shed Management:** ERCOT will work with transmission providers to study the potential use of Advanced Metering Infrastructure (AMI) capabilities in selective load reduction. In addition, increased collaboration will occur between transmission and distribution providers to review existing public policy, bulk power system needs (including natural gas supply points), and practical considerations regarding the management of critical loads.
- **Fuel Supply Issues:** Although fuel-related issues were very limited during the February 2, 2011 event, ERCOT plans to work with state agencies to examine the coordination of natural gas supply and transportation issues, specifically regarding the management of the electrical grid.
- **Communications:** ERCOT will review and update communication policies and procedures related to grid emergencies with regulatory agencies, Registered Entities, and the media. Additionally, a long-term transmission proposal provided by Transmission Operators to provide additional import capabilities in response to the lower Rio Grande Valley load shed event of February 3-4, 2011 is under review. ERCOT believes it has adequate procedures in place to address potential issues for the next winter season.

[12] Severe Weather Readiness Workshop Formerly Generation Weatherization Workshop (http://www.ercot.com/calendar/2011/06/20110608-OTHER).

FRCC Reliability Coordinator

Demand

The FRCC Region experienced expected conditions for the 2010/2011 winter season. The Reliability Coordinator measured actual winter peak demand of 46,220 MW[13] on December 15, 2010. This was less than the previous all time FRCC measured peak of 52,368 MW, which occurred on January 11, 2010. During this period of peak demand, the approximate Operating Reserve level was 7,626 MW, which equates to an Operating Reserve Margin of 16.5 percent.[14] The Region reported a relatively benign winter with no extended cold snaps. No Demand Response was activated during the period of peak demand. A forecasted non-coincident Regional peak demand of 46,235 MW[15] was slightly higher than the actual. The forecasted day-ahead peak demand was higher, at 49,252 MW.[16]

Based on historical demand data, the all time peak occurred during the winter season. However, during five of the last seven years, summer peaks have been higher than the corresponding winter peaks identifying the FRCC Region as typically summer peaking.

Generation and Transmission

There were no delays in the initial operation of new generation units or transmission facilities. There were also no delays in returning units to service after scheduled maintenance. During the seasonal peak for the Region, some planned unit outages were re-scheduled in order to provide increased availability of generation capacity to meet anticipated system demands within the FRCC footprint.

Operational Issues

During the 2010/2011 winter season, the Region reported one double contingency, which caused a Transmission Operator to shed Firm load. The contingency was caused by the loss of two circuits on the same structure (Category Level 5 event). The overhead ground wire failed and dropped into two 138 kV lines, causing damage and required repair prior to returning the lines to service. Simultaneously, a 230/138 kV autotransformer experienced high loading. This resulted in approximately 130 MW of Firm load was being shed for approximately 50 minutes, which was necessary to reduce loading on the facility.

With respect to available generation capacity, there were no reliability concerns with the operation of the three gas pipelines serving the Region. However, as is common practice, to preserve the reliability of the gas pipelines on the cold days, generator operators may opt to

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13 Forecasted peak demand is non-coincidental while measured peak demand is coincidental.

14 The FRCC treats CCDR as a demand reduction in the calculation of Reserve Margin.

15 NERC 2010/2011 Winter Reliability Assessment (http://www.nerc.com/files/2010_Winter_Assessment_V7_ERRATA.pdf).

16 Forecasted peak demand values were consolidated from the forecasted peaks of the individual Balancing Authorities (BAs) to obtain a single forecasted Regional value for the next day.

operate some of their units on liquid fuel in an effort to manage natural gas demand, maintain reliability of the gas pipelines, and meet contractual usage requirements.

The FRCC State Capacity Emergency Coordinator (SCEC) issued two Capacity Advisories during the 2010/2011 winter, both of which were prior to periods of anticipated cold temperatures.[17] During peak the demand day, the Region was in a capacity advisory condition.[18] However, no Emergency Operating Procedures (EOPs) were initiated to maintain system reliability and serve peak demand.

During the 2010/2011 winter peak demand day, the FRCC's largest nuclear plant was not available, due to an extended maintenance outage. However, the Region maintained sufficient operable capacity to serve the peak demand when the Operating Reserves was 7,626 MW,[19] equating to an Operating Reserve Margin of 16.5 percent.

[17] Advisories may be issued based on forecast temperatures in multiple cities exceeding pre-determined temperature triggers.

[18] A capacity advisory is triggered by expected low temperatures at key locations throughout the FRCC Region.

[19] Total resources are obtained by adding the available day-ahead capacity (51,423 MW) and unused available CCDR (2,423 MW) that are projected for system peak. The Reserve Margin, for NERC purposes, is calculated by reducing total resources by the preliminary "actual" peak (46,220 MW provided by the FRCC RC) and dividing again by the preliminary "actual" peak. The FRCC considers CCDR as a demand reduction in the calculation of Reserve Margin obtaining a value of 16.5 percent.

MISO Reliability Coordinator

Demand

The actual peak demand for the Midwest ISO (MISO) was 97,355 MW.[20] FERC's daily report for MISO forecasted a seasonal simultaneous peak demand of 103,254 MW. However, the actual peak demand value was six percent lower, occurring on December 13, 2010 (hour-ending 19:00 EST). The all-time winter peak demand of 103,088 MW was established on February 5, 2007. This season's peak was lower primarily due to alterations in the MISO footprint. Although Big Rivers Electric Corporation joined the MISO footprint, the entire state of Nebraska is now registered within the SPP footprint. Other market changes, such as MidAmerican and Dairyland had negligible impacts. The changes in the footprint, combined with other undetermined variables, has driven down peak load from 2007 levels; however, the MISO market footprint experienced an all-time system peak demand this winter of 91,367 MW, which was 4.8 percent higher than last year's system peak load. The day-ahead peak demand forecast of 97,777 MW was higher than the actual peak demand by 422 MW, reflecting a 0.4 percent difference.

There were wide variations in both temperature and precipitation across the MISO footprint throughout December 2010 when major snowstorms hit the Midwest and High Plains areas. The extreme weather resulted in near-record snow totals in the Dakotas, northwest Iowa, western Minnesota, and the Great Lakes. On December 11, 2010, the MISO issued a Severe Weather Alert through the early morning of December 12, 2010 for the western part of the Region, due to inclement weather caused by heavy snow, high winds, and extreme cold temperatures. The conditions created potential for transmission line icing and galloping conductors.

The MISO currently separates Demand Resources into two separate categories: Interruptible Load and Direct Controlled Load Management (DCLM).[21] While DCLM is typically used for "peak shaving," neither types of Demand Response was used during the 2010/2011 winter.

Generation and Transmission

There were no reliability concerns due to a delay in the initial operation of a unit, or in bringing existing units back into service subsequent to a scheduled outage. All resources performed as expected.

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[20] This hourly integrated average value was based on current reporting methodologies from the FERC daily report and will be used for further calculations in this report. The Regional peak demand for instantaneous load in the Midwest ISO market footprint was 91,367 MW.

[21] Interruptible load is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator.

Operational Issues

There was no loss of Firm load due to the non-performance of Bulk Power System resources. There was also no loss of Firm load due to bulk transmission outages and no fuel situations that impacted the use of resources. No Emergency Operating Procedures (EOPs) were deployed to maintain reliability. During the peak, there were no reported Special Protection Systems (SPS) operations, Remedial Action Scheme (RAS) operations taken, or voltage reductions or public appeals implemented. There were also no voltage reductions or public appeals implemented to maintain the Operating Reserve Margin. Finally, no Firm interchange transactions were interrupted to maintain the Operating Reserve Margin.

NPCC Reliability Coordinators

Demand

ISO-NE

A majority of New England's gas-fired generation fleet primarily burns natural gas under Non-Firm transportation entitlements,[22] ISO New England Inc. (ISO-NE) reports that electric system operations during this winter's peak demand period was tight due to gas supply issues, but manageable[23]. No operational issues materialized that affected system reliability.

In April 2010, ISO-NE[24] forecasted a 2010/2011 winter peak demand of 22,085 MW, which corresponds to a 50/50 reference case peak demand forecast.[25] The 90/10 high case peak demand forecast was 22,765 MW. The winter peak demand generally occurs during January.

From a weather perspective, December 2010, and January and February 2011 were all colder than normal. Below-normal temperatures pushed monthly electricity consumption in New England above 2009/2010 winter values. During the period from Sunday January 23, 2011 through Monday, January 24, 2011, extreme cold weather blanketed the Region.

The preliminary actual 2010/2011 winter peak demand of 21,166 MW[26] occurred on January 24, 2011 (hour-ending 19:00 EDT)[27],[28] and was 919 MW (4.2 percent) lower than the seasonal peak demand forecast of 22,085 MW. This peak value was compiled from overnight meter readings and was reported the next morning.[29] The day-ahead peak demand forecast was 21,900 MW, 734 MW (3.4 percent) higher than the preliminary actual.[30]

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[22] Within IS0-NE's 2010 Regional System Plan (RSP10), the 2010 summer generation mix by primary fuel type shows primary-fueled, natural gas-fired generation totaling 13,181 MW. When compared to the generation fleet's total capacity of 31,965 MW, this represents 41.2 percent.

[23] ISO-NE had a Capacity Supply Obligation of 30,521 plus 2,193 MW of capacity bids exceeding the CSO. However, there was about 7,600 MW of unavailable capacity and 300 MW of exports, resulting in a total available capacity of 24,801 MW.

[24] ISO-NE is the Balancing Authority (BA) for the New England subregion and reports a single peak demand value.

[25] This peak demand forecast did not reflect a reduction of approximately 559 MW of "passive" or "non-dispatchable" demand response resources that were embedded within the April 2010 forecast.

[26] Coincidental value obtained from the ISO-NE Morning Report of January 25, 2011. This was the second posting of the ISO-NE Morning Report, time stamped at 08:40:13 EST on January 25, 2011.

[27] The weather-normalized peak demand for the entire 2010/2011 winter season was 21,945 MW.

[28] Approx. 560 MW of passive DR would have to be added back in to the metered demand in order to be able to compare it to the weather normalized peak. The remaining difference can mainly be attributed to the slightly warmer (by 1 degree) temperature on Jan. 24 vs. the temperature on which the 50/50 peak load forecast is based.

[29] Preliminary actual values represent data which has not been adjusted based on updated/revised data (e.g., meter error adjustments) that may be made between the next-day meter value (which will initially be used for this assessment) and the final/official value determined from ISO-NE financial settlements data.

[30] Obtained from the ISO-NE Seven-Day Forecast dated January 23, 2011. This was the third posting of the ISO-NE Seven-Day Forecast, time stamped at 10:06:01 EST on January 23, 2011.

The predominately summer-peaking New England subregion experienced an all-time winter peak demand of 22,818 MW on January 15, 2005.

The peak demand occurred with Regional temperatures at 8°F (with a -15°F dew point.)[31] Specific highlights from the 2010/2011 winter weather and the resultant electricity consumption are as follows:

1) The three-month (December through February) dry bulb Heating Degree Days (HDD) were between 3.4 and 7.0 percent above normal.
2) The three-month (December through February) net energy for load was between 0.7 and 2.3 percent higher than the 2009/2010 monthly values.

Since no *Emergency Operating Procedures* (EOPs) were required during the winter peak demand day, there was no invocation of “active” or “dispatchable” Demand Response. However, approximately 1,721 MW of dispatchable Demand Resources was available for activation.

Maritimes

The actual 2010/2011 winter peak demand of 5,252 MW[32] occurred on January 24, 2011 (hour-beginning 07:00 ADT). The actual peak was 364 MW and 218 MW below the seasonal forecast and day-ahead forecasts (respectively). These difference can be attributed to warmer than expected temperatures. The Maritimes Area did not experience any unexpected extreme weather conditions. Demand Response programs are not available during the winter seasons.

NYISO

The New York Balancing Authority 2010/2011 winter peak demand forecast was 24,289 MW, slightly lower than the actual peak demand of 24,654 MW, which occurred on December 20, 2010 (hour-ending 18:00 EST).[33] The day-ahead forecast was 23,878 MW, also slightly lower than the actual peak by 776 MW (-3.5 percent). Demand Response was not deployed/activated during the time of seasonal peak demand.

The actual temperature experienced during the day of peak demand was only 18°F, less than the composite statewide average temperature forecast of 22°F. Based on an approximate response rate of 150 MW per degree, the -4°F difference in temperature explains 600 MW of the 776 MW forecasted error. The weather-adjusted forecast of 24,478 MW, with an error of 0.71 percent.

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[31] The temperature reference reflects an 8-city weighted dry-bulb temperature at the time of the peak hour and the dew point reference reflects an 8-city weighted dew point temperature at the time of the peak hour.

[32] The Maritimes Area load is the mathematical sum of the forecasted or actual peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). The actual peak was coincident for the sub-areas.

[33] The peak demand values are for the New York Balancing Authority area as a single NPCC subregion. This value represents the coincidental peak demand for the New York control area.

Ontario

The Independent Electricity System Operator (IESO) directs the operation of the IESO-controlled grid and administers the electricity market for the province of Ontario. The IESO forecasted normal weather peak demand for the 2010/2011 winter was 22,271 MW, slightly lower than the actual winter peak demand of 22,733 MW, which occurred on January 24, 2011 (hour-ending 19:00 EST).[34] The day-ahead forecast had predicted a coincident peak demand of 21,140 MW. On a weather-corrected basis, peak demand was 22,695 MW. The 2010/2011 peak demand was about 2,200 MW less than the all-time Ontario winter peak of 24,979 MW (December 2004).

As indicated by the direction of the weather correction, the peak day weather conditions were slightly colder than normal. The afternoon high for the peak demand day was -12°C (10.4°F). This peak occurred on a Monday following a cold weekend, at which point there was 0.2 MW of economically based Demand Response activated under provincial conservation and Demand Response initiatives.

Québec

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

The actual peak demand for the 2010/2011 winter was 37,717 MW[35] for the Québec Area, occurring on January 24, 2011 (hour-ending 08:00 EST). The actual metered demand (Served Internal Demand) was 36,157 MW at peak.[36] The 2010/2011 winter season also exceeded Québec's previous winter internal peak demand of 37,230 MW.[37]

The Area's two Demand Response programs were both in full use during the period of peak demand, during which point the total interruptible industrial load amounted to 1,560 MW. Specifically, Demand Response consisting of two interruptible load programs – dedicated to large and medium-sized industrial loads – was fully in use at the time of the peak. The two programs provided 1,560 MW of load relief. Therefore, Served Internal Demand was 36,157 MW. During the peak, Hydro-Québec Production exported about 2,333 MW to neighboring NPCC subregions while Hydro-Québec Distribution imported 1,739 MW for its own load. About 957 MW was wheeled through the system by third parties. Operating Reserve Margin

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[34] The peak demands presented in this report are for the IESO-controlled grid and are always coincident peaks.

[35] This value represents the Hourly Internal Peak Demand.

[36] The actual monthly peak internal demands are determined by the Statistics Unit at System Control and Operations (Contrôle et exploitation du réseau).

[37] January 16, 2009 (hour ending 08:00 EST).

requirements were met at all times. No Firm load or Firm transactions were interrupted in any way during the winter period.

Québec forecasted a peak demand of 36,945 MW[38] for the 2010/2011 winter season, 772 MW less than the actual. The Québec Area is winter peaking and electric space heating requires an appreciable amount of load during winter – especially during episodes of very cold weather. This typically increases annual peak demands. However, relatively normal temperatures were experienced during the 2010/2011 winter, aside from a severe cold spell from January 21-25, 2011. Extreme cold temperatures drove the winter peak demand to a new all-time record in Québec.

Daytime temperatures in Montréal during the cold spell were approximately -26°C to -28° C (-15°F to -18°F) during the days leading to the winter peak. The temperature in Montréal during the peak was -8°C (-18°F) and wind speed was 9 km/hour (6 mph). Temperatures in most other areas of the province were below -30 °C (-22 °F) during the peak.

Generation and Transmission

ISO-NE

There were no delays to any new resources expected to be commercialized prior to, or during the 2010/2011 winter period. However, there were some concerns due to generation outages that surpassed the expected completion dates in the late fall and instead extended into December. During the beginning of December 2010, these maintenance overruns totaled approximately 1,900 MW, but decreased to approximately 1,300 MW by the end of the month. There were other supply-side resources available for dispatch to cover the capacity, energy, and operating reserve needs of the system.

ISO-NE has taken a conservative operational approach to managing potential issues caused by the significant unavailability of gas-fired units during extreme winter weather events. This scenario occurred on January 24, 2011, during the Area's peak demand day. ISO-NE responded by supplementing its normal commitment of resources to ensure reliable operations for the Region by taking into consideration the type of fuel the resources were burning – and in some instances, bringing additional oil-fired capability online to compensate temporary natural gas curtailments.

There were no reliability concerns created by delays in achieving commercial operation of any new transmission facilities prior to or during the winter and because of this, no special guides or operating procedures were needed to maintain system reliability.

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[38] Represents the hourly peak demand estimated from total metered demand and measured Demand Response used at the time. Constitutes Québec's published internal peak demand and is comparable to the Seasonal peak Demand Forecast.

As noted within ISO-NE's pre-seasonal winter assessment, since there are only 60 MW of Existing, Certain commercial wind capacity on the New England bulk power system, there were no reliability issues concerning wind power performance during the 2010/2011 winter peak period.

Maritimes

There were no reliability issues attributed to generator outage extensions or units in "cold reserve" status; nor were there any reliability issues attributed to delays in transmission facilities achieving commercial operation.

The Maritimes Area did not apply any wind curtailments. Each sub-area within the Maritimes Assessment Area applies their own seasonal capacity factor, which vary from zero to forty percent. As a whole, the Maritimes Area winter season capacity factor is approximately twenty-four percent.

NYISO

There were no delays when bringing units into service from any type of outages, and there were no delays in achieving commercial operation of new transmission during this season.

Ontario

There were no delays in bringing new units into service or existing units back into service following scheduled outages. Three wind projects (Talbot Windfarm (99 MW), Kruger Energy Chatham Wind Project (101 MW) and Gosfield Wind Project (50 MW)) totaling 250 MW of nameplate capacity, were brought into service during the 2010/2011 season. There were no wind curtailments initiated during the 2010/2011 winter.

There were no "cold reserve" units within the Ontario area and no new significant transmission projects were scheduled to for initial service during the 2010/2011 winter.

Two of the Niagara 345 kV interties (PA301 and PA302) between Ontario and New York were on planned outages during November and December of 2010. In order to prepare for these planned outages, the IESO and NYISO performed joint studies with certain outage conditions. The study indicated a need to bring the Beck-Packard 230 kV BP76 tie between Ontario and New York into service through the duration of the two outages. The BP76 tie had been out of service since 2008, due to the failure of the regulating transformer R76. For these outages, Hydro One built a bypass facility around the failed R76 regulator that allowed the BP76 circuit to be returned to service.

The PA301 and PA302 outages severely restricted the transfer capability on the Ontario-New York and Ontario-Michigan interfaces, but were successfully managed through coordination and planning activities between the IESO and NYISO, as well as the operational flexibility that the BP76 tie offered.

During the winter season, Ontario typically experiences peak load demand during the evening (typically between hours 17:00-21:00 EST). A sample of hourly wind output coincident to these evening hours from December 2010 to February 2011 was observed to represent the "actual on-peak capacity factor" for wind. Specifically, the median value for this sample set was found to be 33 percent—in line with projections.

Over the period December 2010 to February 2011, Ontario's grid-connected wind farms produced over 1 TWh of electricity, resulting in an average energy capacity factor of 37 percent.

Québec

No new generating stations or generating units were forecasted to be commissioned for the winter 2010/2011 operating season.[39] Therefore, there were no delays in the initial operation or commissioning of units. Nor were there any delays in bringing existing units back into service after a scheduled outage for the winter operating period.

No "cold reserve" units were used during the 2010/2011 winter. The only such generating station within the subregion had four oil-fired units. One unit was retired while three others have been mothballed indefinitely, as of April 1, 2011. About ninety-four percent of the resources on the Québec system are hydro, a majority having large multi-annual reservoir hydro capabilities.

The only form of variable generation within Québec includes 659 MW of nameplate wind capacity with a reported maximum output of 591 MW. Average hourly output during 2010 was 179 MW.[40] During the Area's peak demand, wind farm generation output was approximately 448 MW, corresponding to 68 percent of installed capacity. Average hourly output over December, January and February was 213 MW.[41]

The transmission projects mentioned in the NERC Winter 2010/2011 Assessment such as the Anne-Hébert 315/25 kV Transformer Station were effectively commissioned in scheduled time. No reliability problem would have been caused if delays had been encountered. No bulk transmission facilities were scheduled to be commissioned prior to the winter season and all transmission was available at peak.

Operational Issues

ISO-NE

The reliability of the Region's bulk power system was maintained during this winter's peak demand period because of conservative operational steps taken in advance of and during cold weather. These steps included close coordination with the Regional natural gas pipelines and

[39] NERC 2010/2011 Winter Reliability Assessment (http://www.nerc.com/files/2010_Winter_Assessment_V7_ERRATA.pdf).

[40] 27.1 percent global plant capacity factor.

[41] 32.3 percent global plant capacity factor.

verification of gas supplies for those gas-fired generators committed during the extreme cold weather. In addition, there was a marked increase in natural gas prices in New England during the period which economically increased the commitment and dispatch of oil units. To ensure reliable operations for the Region during periods of extreme weather such as that experienced during the January 24, 2011 peak demand day, ISO-NE supplements its normal commitment of resources by committing additional resources to increase fuel diversity. Given the trend towards increased natural gas use and the 2010/2011 winter's operational experience, ISO-NE intends to analyze several market and operational enhancements as part of its Strategic Planning process.[42] In undertaking these assessments, ISO-NE will coordinate in conjunction with Regional stakeholders.

There was no loss of Firm load due to the non-performance of any bulk power system resource or outage of any bulk transmission facility.

There were no major issues with Regional fuel supplies of coal, oil (heavy or light), Liquefied Natural Gas (LNG), or the nuclear fuel cycle during winter. Liquid fuels were readily available.

There were some issues within the Regional natural gas sector which included:

- Minor issues with natural gas quality/interchangeability;
- Some gas curtailments to generators located behind Local Distribution Company (LDC) citygates;
- Some operational problems on in-region natural gas pipelines; and
- Some leaks and ruptures on some upstream natural gas pipelines.

Although communications between Regional gas pipelines and ISO-NE were timely with respect to early notifications, the types of *"force majeure"* events listed above resulted in reliability concerns within New England as Regional gas markets *"rebalance"* themselves. Due to the operating experiences this past winter, ISO-NE decided to investigate a number of possible operational and market enhancements.

As noted earlier, during late January 2011, extreme cold weather covered the Region. In anticipation of this extreme cold weather, on Thursday, January 20, 2011, ISO-NE invoked a *"Cold Weather Watch"* for both Sunday and Monday (January 23 and 24) in accordance with Market Rule 1 – Appendix H – *Operations During Cold Weather Conditions*. While ISO-NE's declaration of the *Cold Weather Watch* is indicative of upcoming severe winter weather, projections for operable capacity margins remained tight, but with surplus. ISO-NE implemented Master/ Local Control Center (M/LCC) Procedure #2 – *Abnormal Conditions Alert* at 15:00 (EDT) on January 23, 2011.

[42] More information on ISO-NE's Strategic Planning Process can be located at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html

In anticipation of the upcoming cold weather and the foreseeable impacts on unit availability, ISO-NE Operations adhered to a pre-planned, conservative system commitment and dispatch, which also included:

- Daily conference calls between ISO-NE Operations Management and equivalent Northeast Power Coordinating Council (NPCC) staff.
- Increased communications with Regional gas pipelines and LDCs.
- Cancellation of all transmission work that may have impacted Regional transfers and generating unit availability.
- For each day until the *Cold Weather Watch* ended, ISO-NE verified with each gas-fired unit that was scheduled to operate, that their next-day gas supplies had been procured and scheduled.

During this two day event, between 3,400 MW and 3,700 MW of outages and reductions were experienced by Regional power generators[43] On January 24, 2011, peak electrical demand and operating reserve requirements were satisfied with no major impacts on system reliability. No other *"Emergency Operating Procedures*" were invoked during the winter period.

Additionally, to maintain both system and sub-area reliability during the 2010/2011 winter season, there were:

- No operation of Special Protection Systems (SPS) or Remedial Action Schemes (RAS);
- No voltage reductions or public appeals;
- No interruptions to capacity interchange transactions.

Appendix I reflects New England's on-peak resource adequacy conditions during the winter peak demand day.

During the winter peak demand day, actual peak operating reserves were 2,852 MW compared to an Operating Reserve Requirement of 1,920 MW, providing a 932 MW surplus for satisfying the Operating Reserve Requirements for the peak hour of the day.

Maritimes

The Maritimes area did not experience any significant operating issues during the winter 2010/11 season.

NYISO

The New York sub-region did not experience any significant operating issues during the winter 2010/2011 season.

Ontario

The IESO experienced three events that resulted in non-consequential (not directly connected to the faulted equipment) load loss during the winter period. In each case, a fault in the Greater

[43] On Sunday January 23, 2011, ISO-NE identified approximately 3,437 MW of generator outages and reductions within its Morning Report. On Monday January 24, 2011, ISO-NE identified approximately 3,707 MW of generator outages and reductions within its Morning Report.

Toronto Area resulted in a dispersed loss of load. The IESO is working with facility owners and customers to understand the locations and cause(s) of the load losses. A detailed report regarding IESO events was submitted to the NPCC Event Analysis Team and the NERC Event Analysis Working Group and is expected to be released in the fall of 2011. This report provides additional details on the following events:

- In the first event on January 24, 2011, two 230 kV circuits tripped and reclosed automatically due to a damaged disconnect switch. The non-consequential load loss was 200 MW. The load was recovered immediately.
- On February 18, 2011, a 3-phase ground fault removed a 230 kV circuit from service. Co-incident with the fault, two other 230 kV circuits auto-reclosed and both the terminal breakers at a generation station opened. The causes of the circuit trips and the terminal breaker misoperation as well as the reasons behind the load loss (described below), are still under investigation. As a result of the fault, there was a non-consequential load loss of approximately 720 MW and 823 MW of generation loss.
- On March 18, 2011, two 230 kV circuits and two busses at a transformer station were automatically removed from service due to the explosive failure of a 230/28kV transformer and simultaneous trip of its companion transformer. The resulting fire and debris likely caused the trip of the companion transformer and associated busses/circuits. Both transformers were destroyed in the fire. The facility owner has developed a multi-disciplinary team to conduct an in-depth failure investigation to determine the root cause of the failed transformer. Because of the failure, the Ontario area observed an interruption of 32 MW of directly connected load, as well as 608 MW of non-consequential load.

Except for the events described above, the IESO did not experience any other operating issues during the 2010/2011 winter season. The operating reserve required for the winter peak day was 1,553 MW while the actual reserve available was 7,640 MW.

Québec

No extreme operating issues challenged the subregion during the Winter Operating Season. An ice storm and wind condition occurred on the North Shore of the St. Lawrence River in early December 2010. This forced gas turbine start-up, utilization of imports from a neighboring system, and Non-Firm transaction curtailments. No loss of Firm load or Firm transactions due to non-performance of a bulk power system element occurred. Prior to the cold spell, a public appeal was called by Hydro-Québec to inform customers of the upcoming cold conditions for Monday, January 24 and Tuesday, January 25, 2011 to reduce their consumption during peak hours. The effect was estimated at 200 MW at peak time. No Firm transactions were curtailed during the Winter Operating Period.

During the 2010/2011 winter, the required 30-minute reserve was 1,500 MW and the actual reserves were about 2,500 MW. This operating reserve also included approximately 1,000 MW of synchronous hydro reserve to instantaneously support frequency after a loss of generation. The Operating Reserve Requirement was met at peak and at all times during the winter operating period.

No new generation was commissioned prior to the winter period, however a number of non-bulk power system transmission projects were commissioned as scheduled.
No extreme issues occurred during the actual peak but some operating issues did occur during the winter period. An ice storm episode occurred in early December 2010, causing the trip-out of two 735 kV lines in the same corridor. An operations problem at Châteauguay HVdc converter station occurred during the peak time due to extreme cold weather, and will be covered in a later section.

Seasonal Experiences and Lessons Learned

ISO-NE

One of the most important challenges of operating the bulk power system in New England during winter is managing the large quantity of long, start-up-time, fossil-based generation. This issue requires ISO-NE to ensure that it has a high level of accuracy in forecasting both Regional demand and cold weather unit availability. Because of this, the subsequent scheduling, commitment and dispatch of Regional generation to satisfy both daily peak demand and operating reserve requirements are managed conservatively during periods of extreme weather, such as those experienced during the January 24, 2011 peak demand day. During these periods, ISO-NE supplements its normal commitment of resources to ensure reliable operations for the Region by taking into consideration the type of fuel the resources are burning, and in some instances, starting additional oil-fired capacity in case of natural gas curtailments.

Given the trend towards increased natural gas use within New England's power sector and the recent wintertime operational experience, ISO-NE intends to analyze several market and operational enhancements as part of its Strategic Planning process, which includes the following objectives:

- Conduct an updated natural gas study to:
    - Determine a range of reliable, dependable capacity for New England, once all Regional Firm gas demands have been considered.
    - Assess electric and natural gas system interdependencies during abnormal events like rolling blackouts and system restoration.
- Assess performance incentives to enhance inter-temporal constraint flexibility, in order to reduce uplift costs and enable a more reliable and efficient dispatch of supply-side resources with long start-up-times.
- Enhance the current resource audit plan to allow for unannounced capability audits.
- Evaluate forward and real-time requirements for ten-minute reserves.
- Evaluate performance incentives and obligations for resources that participate in the Locational Forward Reserve Market (LFRM) and the power system's Black-Start Plan.
    - Investigate whether these resources should be required to have Firm gas or dual fuel.
- Enhance performance incentives for Forward Capacity Market (FCM) resources with Capacity Supply Obligations (CSO).
- Seek better alignment between the natural gas and Regional electric market.

- Assess whether gas-fired units might need to be committed prior to the current Day-Ahead Market (DAM), in order for them to Firm up both gas supply and transportation and recover those cost.
- Assess whether to allow for real-time hourly offers, which should improve real-time pricing.

In undertaking these aforementioned assessments, ISO-NE will coordinate with Regional stakeholders.

Maritimes

Although the Maritimes Area is winter-peaking, the most important operating challenges involve managing severe weather events. There were no issues to report during the 2010/2011 winter.

NYISO

There were no specific challenges in operating the bulk power system besides the typical operating challenges and there were no specific lessons learned during the 2010/2011 winter.

Ontario

Over the course of winter 2010/2011, the IESO did not experience any significant challenges that affected the reliability of the bulk power system. As indicated above, the analysis of the contingencies that resulted in the loss of non-consequential load is expected to be released in the fall of 2011.

Québec

Operating the bulk power system in the Québec subregion does offer a number of challenges. As mentioned earlier, the subregion is strongly winter-peaking. This winter peaking characteristic is due to the large amount of electrical space heating in Québec. Consequently, morning load pick-up on the system 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 south and must be served through a long 735 kV system. Distance from the Montréal area (the largest load center) to the large generation facilities is approximately 1,000 km (600 miles). Five 735 kV interfaces along the system have operating limits and must be monitored at all times. The challenge is to minimize bottled generation over these interfaces and to supply load and sales while adequately controlling system voltages and sustaining reserves.

Moreover, winter-related weather offers its own operating issues. In winter, demand variability is closely related to temperature, wind velocity, and sunlight incidence. Load forecasting for the day-ahead and hour-ahead processes relies heavily on precise weather forecasting. The meteorologist/demand forecasting support team is on call 24/7 during cold spells. Other weather-related problems may be due to ice and frost formation on transmission lines. This occasionally causes lines to trip-out because of ground wire breakage and may (as happened during winter 2009/2010) cause a 735 kV line to be in an outage condition for months due to a tower collapse.

Another challenge is that TransÉnergie’s system is a separate interconnection from the Eastern Interconnection, into which other NPCC subregions are interconnected. Frequency regulation is therefore a concern for the system. The normal frequency profile is 59.5 to 60.5 Hz. Frequency bounds following design contingencies are 58.5 and 61.5 Hz. To ensure that the lower bound is not reached after a design contingency (Under Frequency Load Shedding would be triggered) a certain amount of synchronous hydro reserve must be on the system at all times. This amount is determined in real-time from parameters such as system inertia and First Contingency Loss of Generation parameters. Interconnections with other NPCC areas consist either of HVdc ties or radial generation to and from neighboring systems.

On January 24, between 06:00 and 07:00 EST (the peak demand day), there were no transfers between Massena and Châteauguay. Various transactions on the interconnection netted to zero during that hour. Therefore, the HVdc converters operated at 0 MW during that period. At 07:00 EST, the schedule called for imports on the interconnection, but the converters were unable to start-up. Back-up imports were called on from a neighboring system. The cause of the problem was that adjacent station breakers became too cold and began to leak air. It was determined that during extreme cold periods, the converters should not be stopped and that a minimum power should be transferred at all times. Châteauguay procedures will be reviewed and updated accordingly.

Concerning system issues, as mentioned in the Operational Issues section above, an ice storm and wind condition occurred on the North Shore of the St. Lawrence River in early December 2010. On December 2, 2010 at 19:16 EST, Line 7004 (Micoua – Laurentides 735 kV) tripped due to an open phase (broken jumper). This line went back into service on December 9, 2010 at 12:21 EST. On December 6, 2010 at 18:42, Line 7019 (Micoua – Saguenay) also tripped. At that time, two out of the five 735 kV lines on the Manicouagan – Québec Interface were out until December 7, 11:18 EST (a total outage of 16 hours and 36 minutes). This interface transfers power from the Churchill Falls and Manicouagan/Micoua generating complexes (approximately 11,000 MW) to various load areas. These transfers had to be reduced according to system operating strategies. The situation was mitigated through gas turbine start-up, utilization of imports from a neighboring Québec system, Non-Firm transaction curtailments, and cold reserve warm-up procedures (although no cold reserves were used during the 2010/2011 winter). The system was not at its peak demand during this incident.

PJM Reliability Coordinator

Demand

Demand presented in this report is coincident for the entire PJM area. PJM is the Reliability Coordinator for the PJM area. The PJM actual peak demand for the winter 2010/2011 was 0.9 percent higher than the forecasted peak demand. The winter peak demand in PJM is approximately 85 percent of the summer peak demand. PJM is a summer peaking area. This winter's peak demand of 115,807 MW occurred on December 14, 2010 (hour-beginning 17:00 EDT), which is very early in the peak season. The seasonal peak demand forecast was 114,776 MW. The PJM actual peak demand for the winter 2010/2011 was 0.15 percent lower than the day-ahead forecasted peak demand of 115,982 MW. Weather temperature conditions were normal. Icing conditions on distribution-level elements from February 2-4, 2011 caused outages, but did not impact BES reliability during this time. No Demand Response was needed or called over the 2010/2011 winter peak or at any time during this past winter.

Generation and Transmission

There were no delayed in-service dates for new units that caused a reliability concern. There were no delays for scheduled outage units being brought back into service that caused a reliability concern. PJM had no units in a cold reserve status. There were no delays in commercial operation dates of new transmission that caused a reliability concern.
PJM has curtailed the output of wind units during minimum load events on a number of occasions. These curtailments usually occur during the night in the spring and fall, but may sometimes occur at the beginning or end of the winter peak season. Factors include nuclear dispatching activities and maintaining the operation of thermal units to supply the next day's peak.

Operational Issues

PJM experienced several icing issues during the 2010/2011 winter. Icing caused the LaSalle 1 unit to trip due to a flashover on the unit Generator Step-up (GSU) Transformer. The unit was loaded at 1,204 MW prior to the trip. PJM initiated a 100 percent spinning reserves event to restore system Area Control Error (ACE) within 5 minutes. American Electric Power’s (AEP) Hayden 345 kV station also tripped due to icing. The Hayden–Roberts, Hayden–Hyatt, and Hayden–Beatty 345 kV lines were then lost as a result. No reliability issues resulted from this event. The Roberts 138 kV bus also tripped due to icing. This lead to the tripping of six connected lines. Again, this event did not cause any reliability issues. The Yards Creek-Kittatinny 230 kV radial line tripped and locked-out, causing a loss of two Yards Creek generators. No reliability problems were experienced.

During the most severe ice storms between February 2-4, 2011, approximately 158,000 AEP and 84,400 Commonwealth Edison customers were out of service. There was no loss of Firm load due to the non-performance of a bulk power system resource or insufficient capacity resources, because firm load loss was consequential to the loss of non-BES equipment. Restoration was performed at the distribution system level.

During the ice storms, icing on the coal handling system resulted in reduced output from the Powerton 5 and 6 and Conemaugh 1 and 2 generating units. No reliability problems were encountered.

No Emergency Operating Procedures (EOPs) were deployed to maintain reliability. No Special Protection Systems (SPS) were used during the 2010/2011 winter and no voltage reductions or public appeals implemented. Additionally, no Firm interchange transactions were interrupted. PJM's Operating Reserve Requirement on the peak day was 7,314 MW. The actual Operating Reserve was 17,157 MW, 23 percent above the requirement.

Seasonal Experiences and Lessons Learned

Since PJM is a summer-peaking area, extreme weather is the most challenging aspect of operating the PJM system in the winter. Things like extreme temperatures, severe snow events and ice storms can challenge some generator operations. Ice buildup can also affect operation of transmission lines and even trip out whole substations as was the case during this past winter.

PJM uses Cold Weather Alerts to suspend maintenance in case extreme weather is anticipated. PJM operators may also consider implementing conservative operation including controlling for the simultaneous occurrence of more than one contingency, substation circuit breaker outages, circuit breaker failure, and substation bus outages as appropriate.[44] Existing operating procedures were used to adequately maintain reliability.

[44] PJM Transmission Operations (http://www.pjm.com/~/media/documents/manuals/m03.ashx).

SaskPower Reliability Coordinator

Demand

Saskatchewan's winter actual peak demand was 3,203 MW (instantaneous demand). The peak demand occurred on January 12, 2011 (hour-ending 17:00 CDT) during a brief winter cold snap.

Temperatures ranged from 0°F to -22°F, with windy conditions for 24 hours. Internal Saskatchewan generation was adequate to meet winter peak demand with no Demand Response deployed. The seasonal peak demand forecasted in Saskatchewan's Winter Assessment was 3,304 MW (coincident hourly demand) or 3,380 MW (instantaneous non-coincident demand). The actual peak demand was 3.1 percent less than the seasonal peak demand forecasted.

The day-ahead peak demand forecast (instantaneous coincident demand) was 2,880 MW (hour-ending 19:00 CDT), the peak demand of 3,203 MW (hour-ending 17:00 CDT). The forecasted peak demand was 11.2 percent below the actual peak.

Generation and Transmission

Saskatchewan experienced no delays to new unit initial operation or to units being brought back into service after a scheduled outage for the winter. Nor were there any delays in achieving commercial operation of new transmission during the winter.

Operational Issues

Saskatchewan did not experience any significant operating issues during the winter season. SaskPower reservoirs were at normal conditions and regular operating regimes were followed. Reservoir levels were sufficient to meet both peak demand and the daily energy demand.

Actual operating reserve in Saskatchewan at time of winter peak was 281 MW. This represents the total number of MW counted from both non-spinning and spinning units available at that time. At the time of winter peak, Saskatchewan had 256 MW of spinning reserve on-line. Saskatchewan's contingency reserve requirement is 281 MW, based on its largest single contingency. Saskatchewan's spinning reserve requirement is 112 MW (40 percent of its largest single contingency).

Seasonal Experiences and Lessons Learned

With the increased penetration of wind in Saskatchewan and its variability, it is important for system operators to ensure conventional units are available to offset this variability and its potential impacts. Forecasting the amount of wind production to be used during the day is a challenging task. Operators must continually look ahead at what the wind production is forecasted to be at every hour to ensure the system is operated economically and securely. To accomplish these goals a third party consultant service is used for next hour to next day wind forecasts, along with internal unit commitment tools that allow the system operators to manage wind resources and their expected production.

SERC Reliability Coordinators

Demand

The SERC Reliability Corporation (SERC) serves as a Regional Entity with delegated authority from NERC and is divided geographically into five subregions, which are identified as Central, Delta, Gateway, Southeastern, and VACAR. While the SERC Region is comprised of seven Reliability Coordinators and thirty-one Balancing Authorities, all numbers used throughout this reliability assessment are based on the SERC reporting area, which excludes the Dominion area within the VACAR subregion (reported by PJM). All reporting areas are summer peaking, and monthly peak values were used for the actual 2010/2011 winter peak demand values, which were collected from the entities on a non-coincident basis.

The non-coincident preliminary actual 2010/2011 winter peak demand for the entities in the SERC reporting area was 172,291 MW, recorded in December 2010, which exceeded the forecasted[45] total aggregate internal demand of 166,718 MW by 5,573 MW (3.3 percent). Actual peak demand exceeded seasonal forecast peak demand in two of the five subregions. Colder temperatures throughout the 2010/2011 winter, and improved economic conditions, contributed to the differences between actual and forecast system peaks in most areas. Actual SERC peak demand is slightly lower (0.25 percent) than the all-time winter peak demand of 172,730 MW that occurred in January 2010, but new winter peaks were observed in the Delta (23,820 MW) and VACAR (43,258 MW) subregions.

The non-coincident, day-ahead, peak-demand forecast for the SERC reporting area was 170,002 MW with the peak occurring in December 2010. This forecast peak was 2,289 MW (1.3 percent) lower than the preliminary actual 2010/2011 winter peak demand of 172,291 MW. With the use of various software and forecasting methods, most entities reported that there were no material deviations from previous forecast projections, and were consistent with the actual peak.

Many of the SERC reporting-area entities observed below-average temperatures, but not as severe as the prolonged cold weather conditions during the 2009/2010 winter. Storms in the east contributed to setting new peak-demand records for some entities in the VACAR reporting area. Substantial snowstorms in the Central reporting area produced winter-peaking conditions, but due to business and school closings during the storms, a new all-time winter peak was not set. Drought conditions were reported as dry with average rainfall during the period.

Although most entities did not use Demand Response throughout the 2010/2011 winter, approximately 661 MW of Demand Response was in use during the peak. This represents 11.3 percent of the 5,853 MW of Demand Response that was forecasted to be available. Some of the

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45 NERC 2010/2011 Winter Reliability Assessment (http://www.nerc.com/files/2010_Winter_Assessment_V7_ERRATA.pdf).

programs used included interruptible loads, water heater and heat pump control, and Demand Response automation.

Generation and Transmission

No reliability problems during the 2010/2011 winter resulted from the following issues:

- Delays to any new unit initial operation;
- Delays to existing units being brought back into service after scheduled outages;
- Wind curtailments or unfavorable wind generation performances; or
- New transmission failing to achieve commercial operation.

Delays in the return of generation to operation, if any, were adequately communicated from the Generator Owners/Operators to the Transmission Operators and Balancing Authorities to allow mitigation procedures to be developed and employed as needed.

Operational Issues

The SERC reporting areas were able to maintain reliability of the bulk power system during the winter period. However, supply to a local load pocket in Louisiana was negatively impacted on December 27, 2010. Due to the tightly coordinated seam issues along the SPP and SERC boundaries, SERC closely monitors the Acadiana Load Pocket (ALP) for potential reliability concerns. The Southwest Power Pool (SPP) Independent Coordinator of Transmission – Entergy (SPP-ICTE) reported that a Firm loss-of-load event occurred in the ALP, which is located in southern Louisiana and is served by three Transmission Owners: Entergy Gulf States Louisiana, L.L.C., Cleco Corp., and Lafayette Utilities System (LUS). The latter two entities are registered in the SPP Regional Entity (SPP-RE). The ALP experienced a real-time overload as a result of the following conditions:

- Unexpected high loads due to extremely low temperatures;
- The loss of two generators external to the Entergy system but inside the load pocket; and
- The loss of two transmission lines.

After detailed analysis, it was determined that the overload could not be mitigated without shedding Firm load. This local issue resulted in non-consequential load loss.

SPP-ICTE, in its role as the Reliability Coordinator for Entergy, Cleco Corp., Louisiana Generating (LAGN), Louisiana Energy and Power Authority (LEPA), and LUS, directed the load-shed event and required participation from multiple Balancing Authorities that are located within the area. Once the two generators returned to service, and with the addition of a third, the SPP Reliability Coordinator reinstated the load without encountering any issues.

A two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket is currently in the construction phase. Phase 1 is targeted to be placed in service in early May 2011. Phase 2 is targeted to be placed in service by June 1, 2012.

During the season, entities in the SPP-ICTE Reliability Coordinator's area reported that there were a number of pipeline warnings, and notices were issued that limited the hourly and daily swing received at various plants. Additionally, there were some pipeline mechanical and weather-related events that limited fuel supply and flexibility to some plants. Because of these situations, other fuel options such as the use of alternate pipelines, the purchase of additional gas and the utilization of fuel oil were employed to maintain the fuel reliability of the system.

While severe winter weather and minor operational issues had impacts on railroad performance and deliveries to the coal plants, each coal plant maintained sufficient inventory levels to absorb any supply disruptions. There were no material disruptions that impacted supply to, or the availability of, coal units. Entities continue to monitor railroad, supplier performance, plant performance, and pursued initiatives to mitigate risk of coal shortages.

In February 2011, one reporting entity resorted to implementing an Energy Emergency Alert (EEA) Level 2 to maintain reliability as part of their Curtailment and Load Shed Process Procedure. During the 2010/11 winter, no Special Protection Schemes, emergency Remedial Action Schemes, or voltage reductions, were deployed to mitigate significant reliability issues.
Nineteen Firm interchange transactions were curtailed using NERC Transmission Load Relief (TLR) Procedures from December 2010 to February 2011. Most of the events were centered around outages or overloads of high voltage transmission lines on neighboring systems. None of the curtailed Firm interchange transactions had an impact on the operating reserve margins of the SERC reporting areas during the 2010/2011 winter.

Reporting entities within the SERC Region collectively maintained a peak operating reserve margin of 11.6 percent during the winter. Several entities are members of reserve sharing groups, which have various minimum contingency reserve requirements. Entities reported exceeding various requirements within these groups and did not report any issues in meeting existing operating reserve requirements for the 2010/2011 winter peak.

Seasonal Experiences and Lessons Learned

The challenges to operating the bulk power system within the SERC reporting areas during the 2010/2011 winter were generally reported as being the same as those forecasted prior to the winter season. Despite the colder than normal winter weather, tempered by continued depressed economic conditions in most SERC areas, adequate preparation and forecasting ensured a transmission system that proved reliable, resulting in no significant lessons learned during the 2010/2011 winter season.

As stated above, entities within the Acadiana area experienced operational challenges and record cold weather for extended periods, even as they anticipated improvement upgrades currently under construction.

Issues that continue to impact dispatch patterns were related to:

1. System topology (loop flows from neighboring entities);
2. Management of merchant and co-generation activities;

3. Coordination with neighboring transmission systems across seams; and
4. Significant changes in gas pricing.

Transmission constraints that were identified in operations planning studies prior to the 2010/2011 winter season were mitigated through generation adjustments, system reconfiguration or system purchases. Some utilities also reported challenges with the coordination of numerous network transmission customers that were using designated resources to serve customer load. A number of plants and customers' schedules were modified on very short notice, which significantly changed next-day schedules, and created a challenge for real-time operations. Other entities reported that they viewed the lack of available transmission service as a challenge.

Some congestion on the transmission system was experienced, but no event was significant enough to impact reliability. All issues were handled by the protocols of established operating procedures and policies to maintain system reliability. No significant events were reported that required modification of established protocols. However, some reporting entities are considering increasing staffing levels within scheduling departments during extreme cold weather events to handle anticipated schedule changes. Utilities within all reporting areas continue to perform the necessary seasonal studies to help identify possible contingencies and ensure operators are trained to handle situations that may arise.

SPP Reliability Coordinator

Demand

The Southwest Power Pool Reliability Coordinator (SPP RC) footprint experienced a coincident winter peak demand of 41, 076 MW on January 13, 2011 which was slightly higher than the forecasted peak of 40,554 MW. The 2011 peak demand represents an average annual load growth of 2.2 percent. While there is some minimal amount of Demand Response in the SPP RC footprint, widespread use did not occur during the winter of 2010/2011.

Generation and Transmission

The SPP RC footprint experienced two separate events during the 2011 winter assessment period that involved generator resources. As previously mentioned in the SERC section above, the first event occurred on December 27, 2010 in Southern Louisiana in an area known as the Acadiana Load Pocket (ALP). A series of events occurred in the ALP that ultimately resulted in two separate load shed events totaling 277 MW (ALP Event). A contributing factor in the ALP Event was the inability of 200 MW of capacity to start-up, or remain operational due to the extreme cold weather conditions.

The second event occurred during the period February 1-4, 2011 (Winter Weather Event). Three Balancing Authorities in the SPP RC footprint were involved in an Energy Emergency Alert Level ranging from a Level 1 to a Level 3, due to the loss of generating capacity that amounted to approximately 2,384 MW. This was related to extremely cold temperatures and during this period, there was approximately 5,925 MW of capacity offline or limited due to frozen components.[46] Aside from the issues associated with these two events, the SPP RC footprint experienced no other significant resource related issues during the 2010/2011 winter.

Transmission

During the ALP Event, a splice failure caused a transmission line outage and another line to overload. The SPP RC did not experience significant transmission outages during the Winter Weather Event. However, cold temperatures caused some issues for SF6-type gas circuit breakers and the Southwestern Public Service Eddy DC Tie operation. There were no major transmission outages during this event. Other than the ALP Event, the SPP RC footprint experienced no significant transmission outages during the 2010/2011 winter.

Operational Issues

During the ALP Event, the SPP-ITCE directed a total of 277 (MW) of load to be shed. The load shed directives protected the ALP area from a potential failure that could have resulted in the total loss of load serving capability in the Region, and preserved 1,200 MW of additional load. The load shed directives were the result of higher-than-expected demand due to lower-than-

[46] The 2,384 MWs of generation effected by the weather was not offline simultaneously.

expected temperatures. As a result, two quick start generating units in the ALP failed to start. Additionally, a transmission line contingency resulted in a real-time transmission line overload.

The SPP RC footprint had no loss of Firm load during the Winter Weather Event due to non-performance of generation, but gas-fueled generation did note potential limitations during the severe cold weather in February. The Emergency Operating Procedures pre-established for the ALP were used to maintain reliability. Demand Response was not used to provide contingency reserves for reliability purposes.

Seasonal Experiences and Lessons Learned

SPP RTO continues to perform real-time, current day, next day, and seasonal Reliability assessments for the SPP RC footprint. The results of these studies are shared with SPP members and coordination occurs using these studies to prepare to operate the system reliably.

The ALP Event did provide lessons learned opportunities in the following areas:

1. The SPP Reliability Coordination group improved its next-day analysis process by including the temperature used to create their load forecasts. The SPP RC can now assess the next day study against the projected day’s temperature range, and call for a new study (if adjustment becomes necessary). The Acadiana entities should continue to indicate their projected load in the information they provide to the RC.
2. Even though SPP currently relies solely on its members for load forecasting, the RC is evaluating the purchase of load forecasting software.
3. SPP’s Operations Performance Support group will develop a training scenario around this event that will be included in the training simulator. A class to provide the RCs with the opportunity to work in the classroom with the reliability tools used for load shedding will also be developed and offered to all of the ALP Entities.

The Winter Weather Event provided a lessons learned opportunity regarding the loss of capacity that initiated an SPP Operating Reliability Working Group (ORWG) discussion focused on clarification of a procedure (process) for increasing RSG reserve obligations due to real-time events.

WECC Reliability Coordinator

The Western Electricity Coordinating Council (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 between. Due to the vastness 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 post-seasonal assessment, the WECC Region has been divided into four reporting areas:[47]

1. Northwest Power Pool Reserve Sharing Group (NWPP RSG)
2. Rocky Mountain Reserve Group (RMRG)
3. Southwest Reserve Sharing Group (SRSG)
4. California/Mexico (CAMX)

Demand

The peak demand, reserve, and outage values presented in this assessment are daily non-coincident data extracted from the WECC Interconnection Daily Status Report that is posted Monday through Friday (except holidays) on WECC's website. The non-coincident data values in those reports are for the reporting areas described above, and for the entire Western Interconnection.

The peak demand, reserve, and outage values presented in this assessment are daily non-coincident data extracted from the WECC Interconnection Daily Status Report that is posted Monday through Friday, (except holidays) on WECC's website. The non-coincident data values in those reports are for the reporting areas described above, and for the entire Western Interconnection.

Although reporting entities within the Western Interconnection experienced brief periods of record low temperatures, the cold -spells were not widespread geographically. The lack of a widespread cold-spell, and the reduction in demand related to the continued slow economic recovery, resulted in a January 11 non-coincident peak demand that was 0.7 percent less than the seasonal forecast reported in NERC's 2010/2011 Winter Assessment. The seasonal coincident peak demand forecasts reflect normal weather conditions while the actual peak demands reflect actual weather conditions.

[47] The geographic boundaries for three of the four areas differ from the geographic boundaries for the WECC subregions because the NWPP RSG includes California's Balancing Authority of Northern California and Turlock Irrigation District Balancing Authorities, and the SRSG includes California's Imperial Irrigation District

The actual winter WECC non-coincident peak demand of 125,585 MW was 8.1 percent less than the all-time winter non-coincident peak demand of 136,592 MW (December 2008) and was 22.1 percent less than the summer non-coincident peak demand of 161,131 MW (July 2006). WECC is traditionally a summer-peaking region.

The actual non-coincident peak demand of 125,585 MW (Hour-ending January 12, 2011)was 3.7 percent greater than the day-ahead non-coincident forecast of 121,126 MW.

The WECC peak demand occurred as very cold air swept across the Intermountain West with record low temperatures for January 11, 2011, including -40°F in Crested Butte, CO; -26°F in Roosevelt, UT; and -24°F in Stanley, ID. Demand Response was used during the 2010/2011 winter, but not during the peak period.

Generation and Transmission

WECC did not experience any reliability concerns due to either new plants not entering service as scheduled or existing units returning to service late following scheduled outages. Similarly, WECC did not experience reliability concerns due to delays in achieving commercial operation of new transmission.

Operational Issues

On several occasions during the winter season Load-Serving Entities (LSE) within WECC experienced loss of firm load due to insufficient capacity resources. On Tuesday evening, February 1, El Paso Electric Company (EPE) interrupted service to 85 MW of non-firm load (partially Demand-Side Management), followed the next morning by an interruption of service for several hours to an estimated 273 MW of firm load. The evening of February 2, an unspecified amount of firm load reduction occurred for about three hours, followed by a 100 MW firm load reduction on Thursday evening, February 3. Finally, an additional 100 MW firm load reduction occurred on Friday morning, February 4. The firm load reductions were implemented on a rotating basis across the entire EPE system in both New Mexico and Texas. A report on this event is available on the EPE website. As explained in the report, EPE lost most of its local generation because of extended record subfreezing temperatures and severe wind chill.

On the morning of February 2, 2011, Salt River Project (SRP) interrupted service to approximately 300 MW of Firm customer load. Service to most customers was restored within approximately thirty minutes. In addition to the Firm load curtailment, SRP interrupted service to approximately 273 MW of Non-Firm demand for varying periods. The service interruptions were due to a significant generation shortage caused by weather-related outages at several plants. Further details regarding the event are available on the NERC website.[48]

[48] NERC Event Analysis website (http://www.nerc.com/page.php?cid=5).

Other LSEs within WECC also experienced some loss of Firm load due to transmission outages but those loss events were generally storm related and largely involved customers that are on radial transmission lines.

The early February cold-spell that hit the Southwest, including Texas, resulted in natural gas curtailments in portions of southern Arizona, southern California, and New Mexico. However, those curtailments largely affected residential and commercial customers and had no significant affect on electric power generation.

As noted in the EPE and SRP discussions, WECC experienced several Emergency Operating Procedure deployments to maintain reliability. WECC experienced no significant Remedial Action Scheme activations during the winter season and did not experience voltage reductions for reliability purposes. WECC experienced several events during the winter season that resulted in the issuance of an Electric Emergency Incident and Disturbance Report (Department of Energy Form OE-417). Summaries of those events are available on the U.S. Energy Information Administration's website[49]. Only one of the events involved the issuance of a public appeal for energy conservation. Response to that appeal, which occurred in the El Paso, Texas area, was not sufficient to offset the significant generation loss, so rotating power blackouts were implemented to balance load against available resources. None of the events presented in the Form OE-417 reports involved system conditions that significantly affected transfers within WECC.

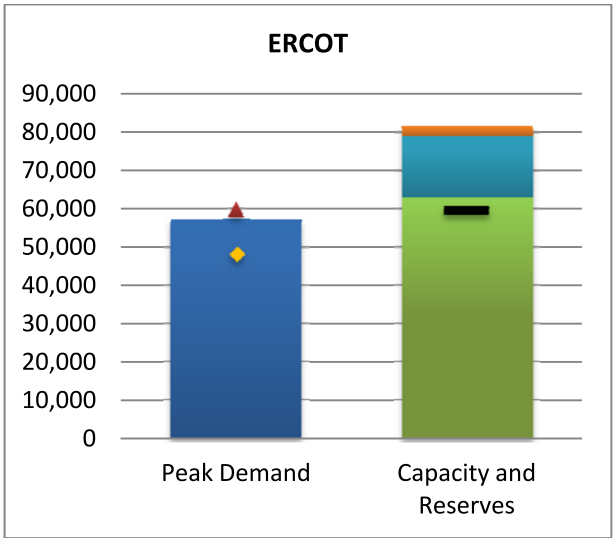
Seasonal Experiences and Lessons Learned

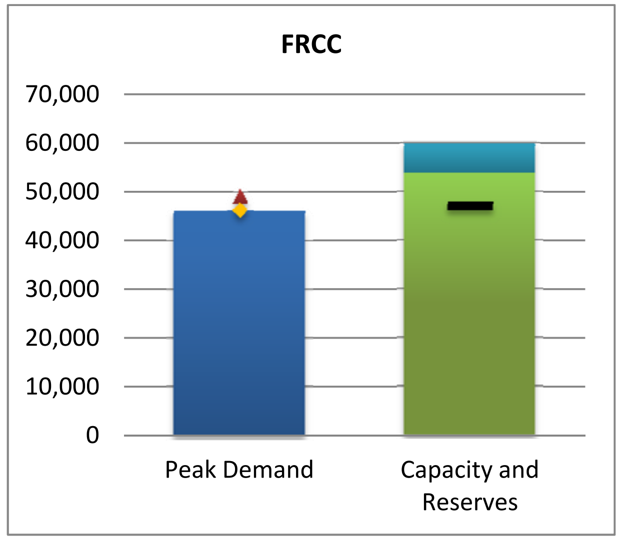
The greatest challenges in operating the bulk power system are preparing for and responding to significant seasonal weather-driven events. These challenges were fully demonstrated this past winter by the power interruptions experienced by EPE and SRP customers as discussed previously. The primary "Lessons Learned" from these events include understanding the need for generator operators to have seasonal weatherization plans, that facilities are properly weatherized, and finally periodic confirmation that plant weatherization measures are functioning properly. As observed in both the EPE and SRP situations, multiple simultaneous events may occur resulting in less than desirable outcomes that cannot be fully mitigated. For example, transmission limitations that could not be completely mitigated resulted in power importation restrictions that adversely affected the El Paso area's load-serving capability for several hours on consecutive days. Event report reviews by WECC staff, and in some cases by NERC staff and other parties, provide an on-going process improvement procedure designed to augment the "Lessons Learned" procedure. It is expected that the EPE and SRP event reviews will result in improved weatherization awareness and practices, and more active weatherization effectiveness reviews.

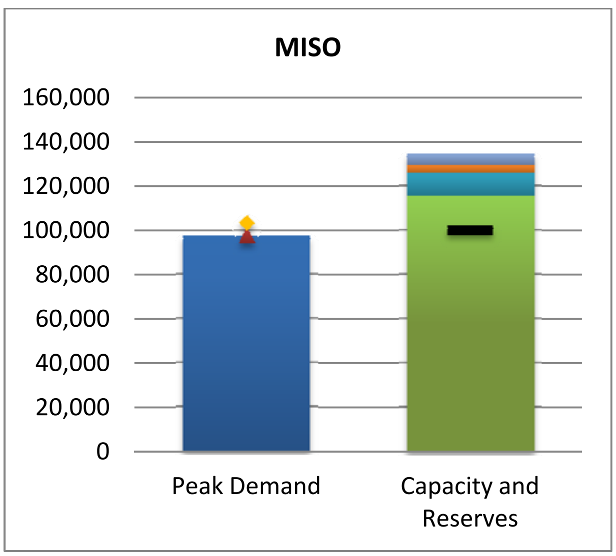
[49] Electric Disturbance Events (OE-417) Annual Summaries (http://www.oe.netl.doe.gov/OE417_annual_summary.aspx).

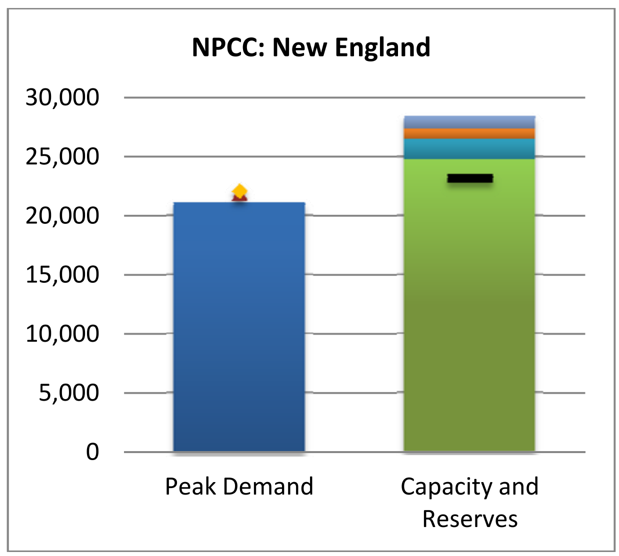
Appendix I: Assessment Area On-Peak Resource Adequacy

Actual Peak Demand | Total Available Capacity | Scheduled Outage | Forced Outage
Generator Derates | Day-Ahead Peak Demand Forecast | Seasonal Peak Demand Forecast | Required Reserves

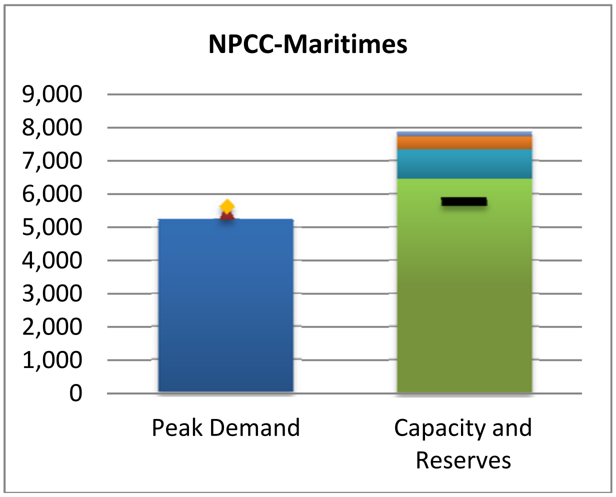


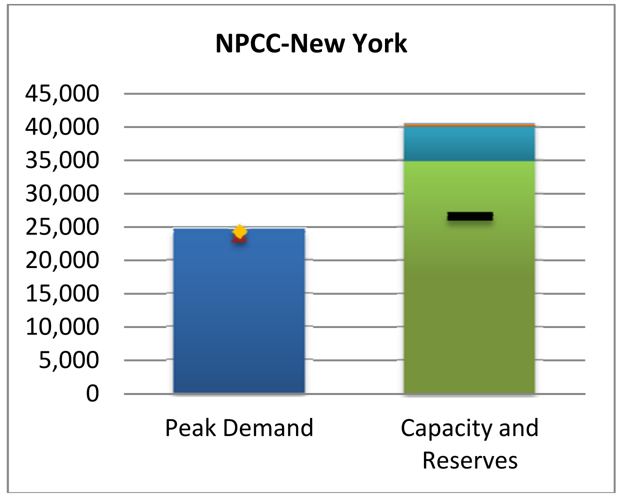


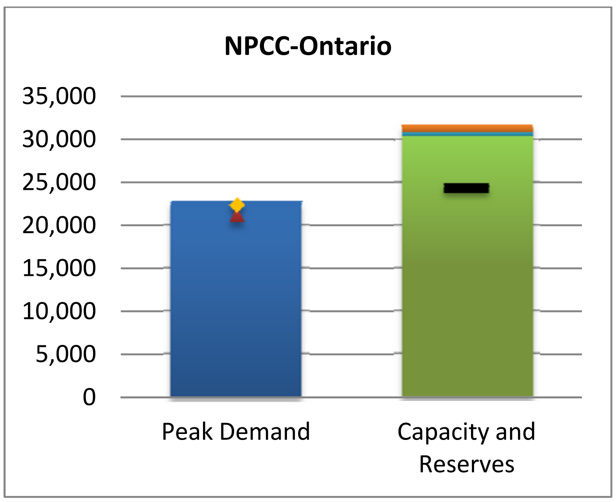


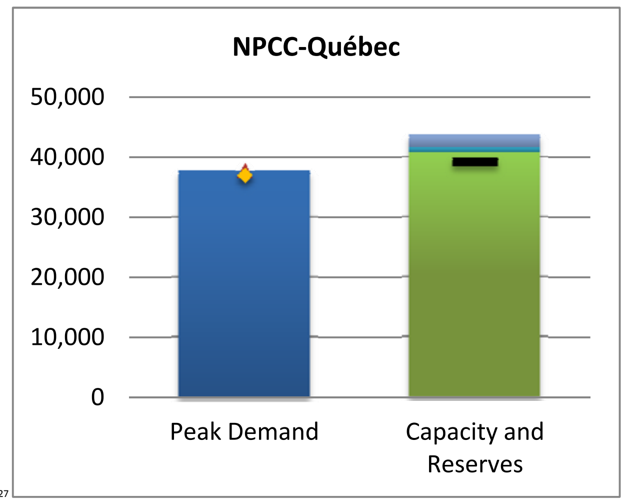


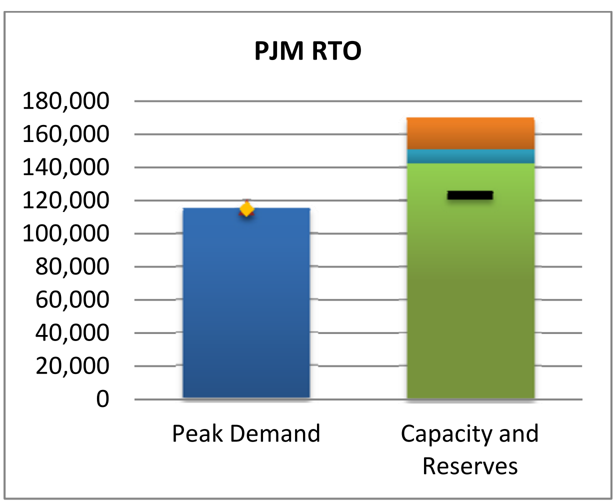
Actual Peak Demand | Total Available Capacity | Scheduled Outage | Forced Outage
Generator Derates | Day-Ahead Peak Demand Forecast | Seasonal Peak Demand Forecast | Required Reserves

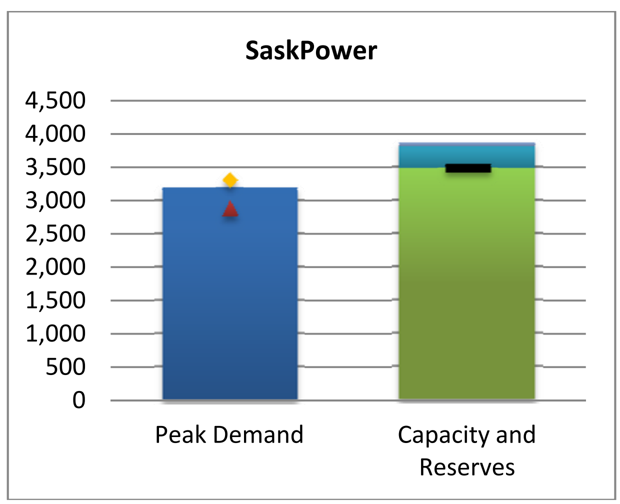




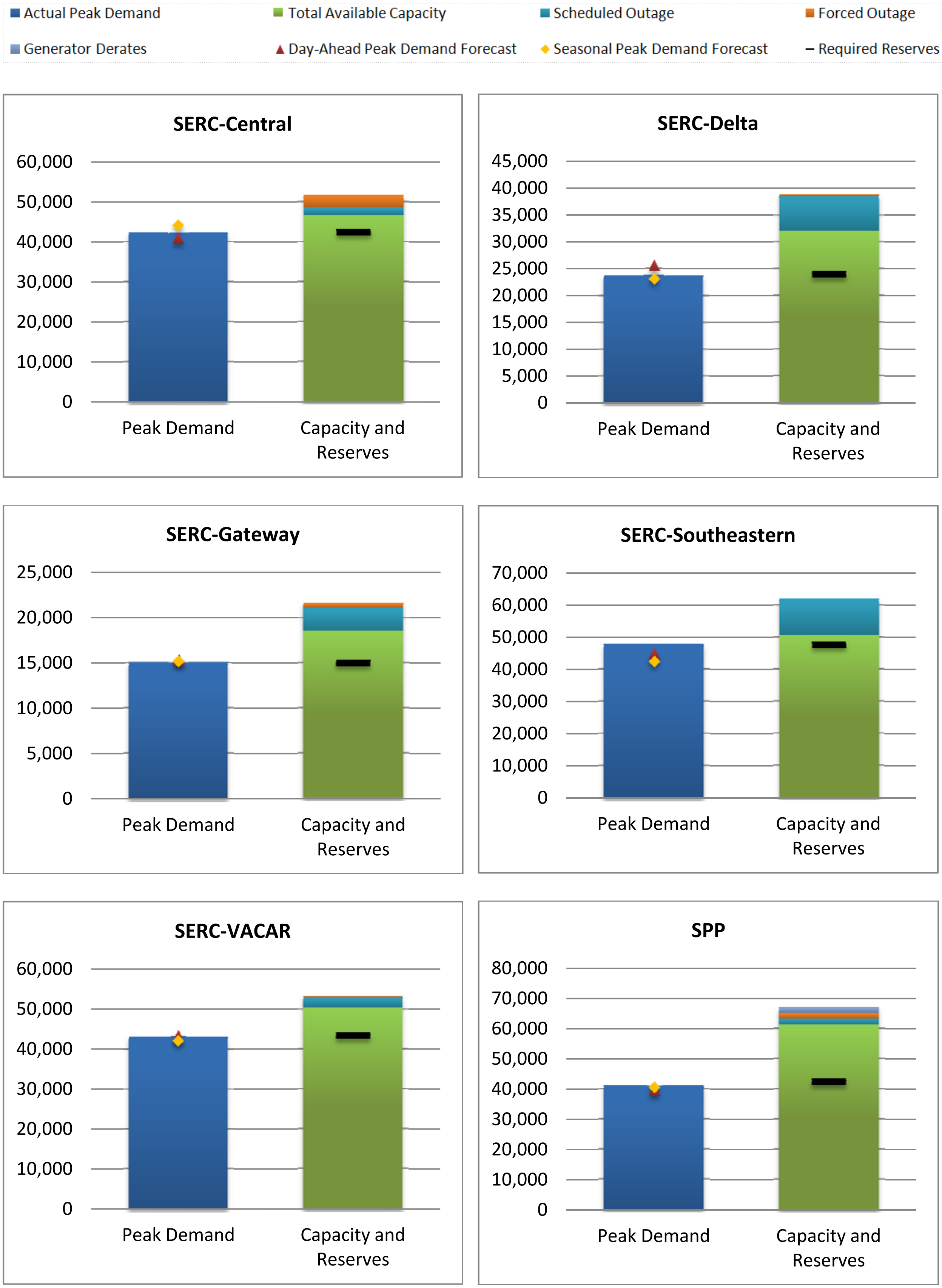


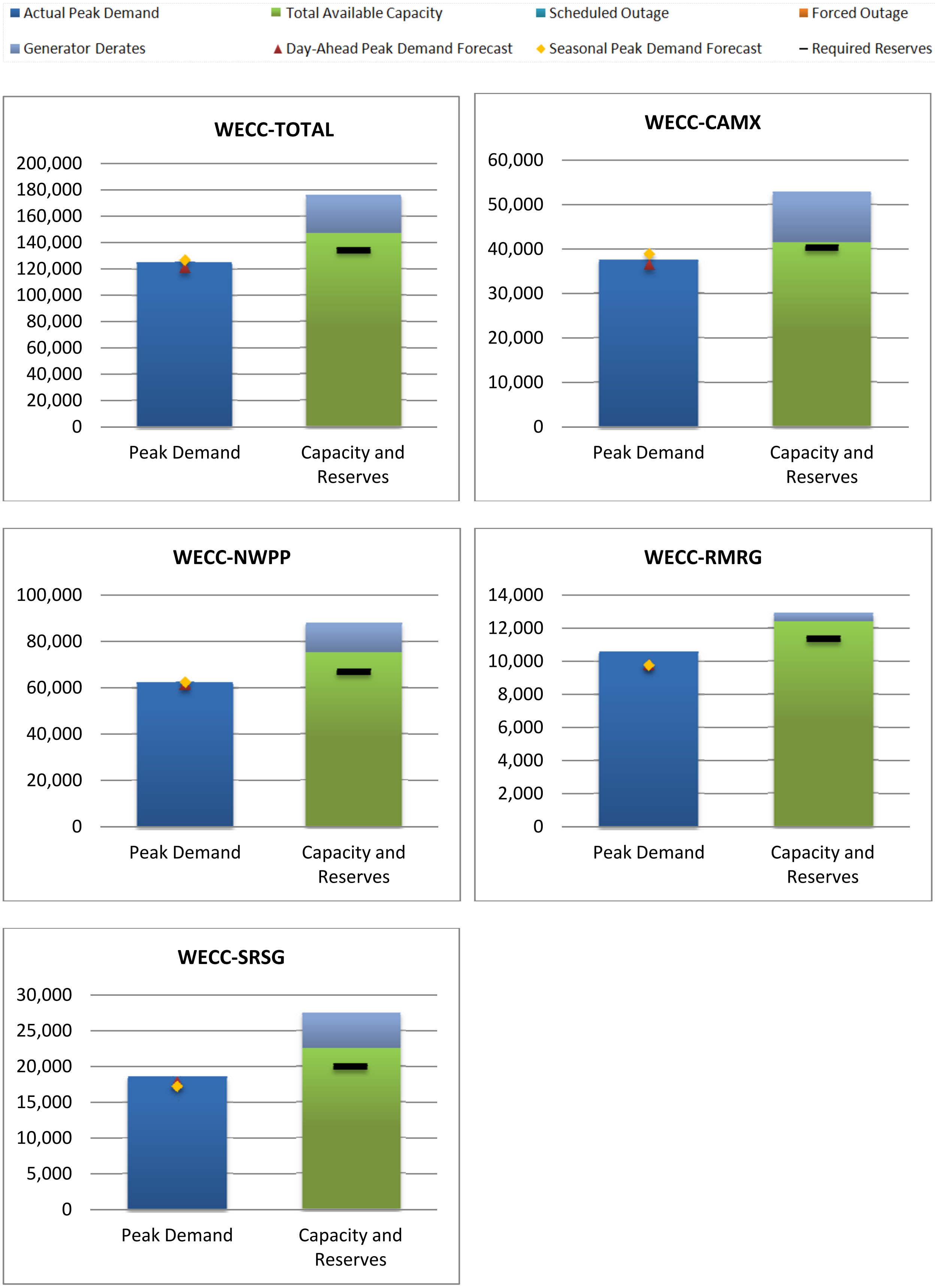






[50] The Internal Peak Demand shown in the NPCC-Quebec table is not the metered "Served Internal Demand."


Actual Peak Demand
Total Available Capacity
Scheduled Outage
Forced Outage
Generator Derates
Day-Ahead Peak Demand Forecast
Seasonal Peak Demand Forecast
Required Reserves
SERC-Central
SERC-Delta
SERC-Gateway
SERC-Southeastern
SERC-VACAR
SPP
Peak Demand
Capacity and Reserves


Actual Peak Demand
Total Available Capacity
Scheduled Outage
Forced Outage
Generator Derates
Day-Ahead Peak Demand Forecast
Seasonal Peak Demand Forecast
Required Reserves
WECC-TOTAL
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Peak Demand
Capacity and Reserves
WECC-CAMX
60,000
50,000
40,000
30,000
20,000
10,000
0
Peak Demand
Capacity and Reserves
WECC-NWPP
100,000
80,000
60,000
40,000
20,000
0
Peak Demand
Capacity and Reserves
WECC-RMRG
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Peak Demand
Capacity and Reserves
WECC-SRSG
30,000
25,000
20,000
15,000
10,000
5,000
0
Peak Demand
Capacity and Reserves

About This Report

This *2010/2011 Post-Winter Reliability Assessment* represents NERC's independent judgment of the performance of the bulk power system in North America for the previous winter season (Table A).[51] The report specifically provides a high-level reliability assessment of 2010/2011 winter resource adequacy and operating reliability, an overview of significant events, seasonal highlights, and self-assessments for each Assessment Area.

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 improvement as needed. Additionally, this assessment offers NERC and its stakeholders the opportunity to assess the reliability preparations documented prior to the season, address any challenges encountered, and provide any operational experiences or lessons learned to benefit of the industry as a whole.

Report Preparation

NERC prepared the 2010/2011 *Post-Winter Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). This 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 performs detailed data checking on the reference information received by the Regions for this assessment. NERC also uses an active peer review process in developing all 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 to ensure the validity of the information provided by the Regional Entities.

[51] Bulk 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:

2010/2011 Post-Winter Reliability Assessment Data Request Letter, March 10, 2011
http://www.nerc.com/docs/pc/ras/2010_PostWinter_Letter_031011.pdf

2010/2011 Winter Reliability Assessment, Updated January 1, 2011
http://www.nerc.com/files/2010_Winter_Assessment_V7_ERRATA.pdf

Glossary of Terms Used in Reliability Standards, March 15, 2011
http://www.nerc.com/files/Glossary_of_Terms_2011Mar15.pdf

Reliability Standards for the Bulk power systems in North America**,** Updated July 28, 2011
http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf

Self-Assessment Request for NERC Post-Winter Operational Reliability, Updated March 10, 2011
http://www.nerc.com/docs/pc/ras/2010_PostWinter_Letter_031011.pdf

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