NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# 2010 Post-Summer Reliability Assessment

to ensure the reliability of the bulk power system

May 2011

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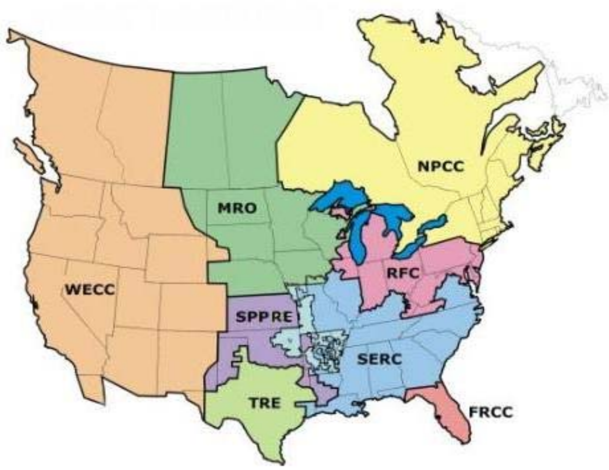
# NERC's Mission

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 ten-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 (ERO) 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**<br>Florida Reliability Coordinating Council | **SERC**<br>SERC Reliability Corporation |
| **MRO**<br>Midwest Reliability Organization | **SPP RE**<br>Southwest Power Pool Regional Entity |
| **NPCC**<br>Northeast Power Coordinating Council | **TRE**<br>Texas Reliability Entity |
| **RFC**<br>Reliability*First* Corporation | **WECC**<br>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.

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# Post-Summer Reliability Assessment Summary

**Overview**

During the 2010 summer, system operators across the NERC Areas maintained bulk power system reliability despite warmer weather in most of the Southeast, Mid-Atlantic and Northeast, as well as parts of the West and Midwest.

**Demand**

Day-ahead forecasted peak demands exceeded forecasted peak demands in many Areas (see *Table 1*). Specifically, ERCOT experienced an all-time summer peak demand of 65,716 MW, 2.6 percent higher than forecasted and 5.1 percent higher than the Region's previous all time peak of 62,339 MW (August 2006). With the exception of the Maritimes subregion, the NPCC Region experienced higher-than-forecasted peak demands with New England observing record peak demand levels during May and September, along with an all-time record for monthly energy use in July. The SPP Regional Entity also established a new all-time summer peak demand of 53,146 MW, exceeding the previous all time peak of 50,898 MW (August 2008) by 4.2 percent.

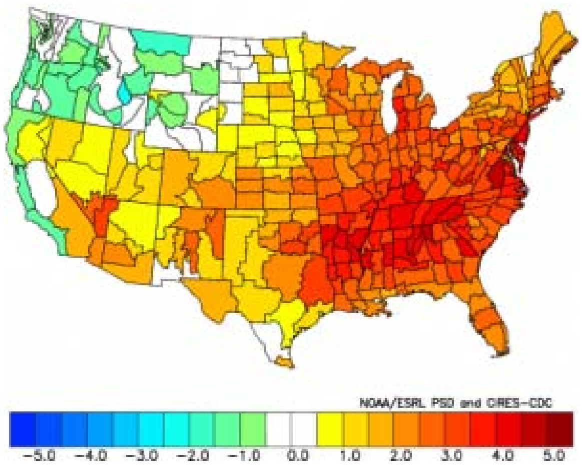
The MISO also reported a very warm summer, especially during the peak month of August when persistent high temperatures and relative humidity, combined with variable precipitation resulted in declarations of several Hot Weather Alerts. During the same month, the area's load-weighted Heat Index and Hourly Real-Time Load reports drastically exceeded those of a year earlier.

Regions within the Western Interconnection experienced brief periods of record high temperatures with certain entities reporting new all time peak demands. However, reduction in demand due to the continued slow economic recovery offset what would have been weather-related demand increases. SERC's report was similar, attributing economic conditions combined with consistent rainfall as primary factors in counteracting the impacts of above-normal temperatures.

Other areas including SaskPower, PJM, and FRCC experienced expected temperatures with peak demands that were comparable to their forecasts.

According to the National Oceanic and Atmospheric Administration (NOAA), the contiguous United States had its fourth-warmest summer (June-August) on record, which some areas breaking regional all-time records (see *Figure 1*).[2] August was the second warmest month on record for Florida, Louisiana, and Tennessee, with fourteen other states also reporting temperatures among their warmest ten percent. No state experienced an average temperature significantly below its long-term average. For most areas, higher than normal average temperatures primarily contributed to higher electricity use (MWh) across all summer months, while less significant impacts to peak demands (MW) were also observed.

**Figure 1: U.S. Temperature Anomalies Jun to Aug 2010**




[2] Because most Canadian assessment areas are winter-peaking, the Temperature Anomalies figure was omitted for this report.



Post-Summer Reliability Assessment Summary

**Table 1: Day-Ahead vs. Seasonal Peak Demand Forecast**

| Areas | 2010 Forecast Summer Peak Demand (MW) | Day-Ahead Forecasted Peak Demand (MW) | Difference (MW) | Difference (%) | Summer 2010 Month of Peak Demand |
|---|---|---|---|---|---|
| ERCOT | 64,056 | 64,131 | 75 | 0.1% | August |
| FRCC | 46,034 | 45,812 | -222 | -0.5% | August |
| MISO | 109,990 | 112,494 | 2,504 | 2.3% | August |
| NPCC | 107,696 | 109,674 | 1,978 | 1.8% | Multiple |
| ISO-NE | 26,618 | 26,800 | 182 | 0.7% | July |
| Maritimes (NBSO) | 3,878 | 3,305 | -573 | -14.8% | September |
| NYISO | 33,025 | 32,675 | -350 | -1.1% | July |
| Ontario | 23,498 | 24,844 | 1,346 | 5.7% | July |
| Québec | 20,677 | 22,050 | 1,373 | 6.6% | July |
| PJM[3] | 135,380 | 135,784 | 404 | 0.3% | July |
| SaskPower[4] | 2,931 | 2,710 | -221 | -7.5% | July |
| SERC[5] | 181,570 | 180,435 | -1,135 | -0.6% | August |
| Central | 42,364 | 42,509 | 145 | 0.3% | August |
| Delta | 27,944 | 27,958 | 14 | 0.1% | August |
| Gateway | 19,113 | 19,503 | 390 | 2.0% | August |
| Southeastern | 48,472 | 48,131 | -341 | -0.7% | July |
| VACAR | 43,677 | 42,334 | -1,343 | -3.1% | August |
| SPP | 54,974 | 52,743 | -2,231 | -4.1% | August |
| WECC | 148,365 | 145,387 | -2,978 | -2.0% | August |
| CA-MX | 59,612 | 54,254 | -5,358 | -9.0% | August |
| NWPP RSG | 54,120 | 54,348 | 228 | 0.4% | August |
| RMPA | 10,979 | 9,326 | -1,653 | -15.1% | August |
| SRSG | 27,816 | 27,459 | -357 | -1.3% | August |

[3] Operates in RFC and SERC

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

[5] 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). Additionally, the SERC reporting area monthly peak values were used for the preliminary "actual" 2010 summer peak and were collected from the entities on a non-coincident basis.

## Operations

Reliability Coordinators in all areas sustained adequate operating reserves during peak conditions, resulting in no uncontrolled Firm demand interruptions during the 2010 summer season that impacted the reliability of the bulk electric system. ERCOT initiated two Emergency Operating Procedures (EOPs) that resulted in two periods of Energy Emergency Alerts (EEAs) – Level 1, but these incidents did not occur during periods of peak demand. For the FRCC Region, the State Capacity Emergency Coordinator (SCEC) issued five capacity advisories due to hot seasonal temperatures experienced in Florida, but these advisories did not occur during periods of peak demand. The MISO declared three hot weather alerts along with conservation operations for three days in mid-August. Additionally, a maximum generation emergency alert was declared in northeast Ohio, due to generation loss in the area. There were multiple PJM-forced transmission outages; however, no EOPs were deployed to maintain reliability within the footprint.

The NPCC subregions of Ontario and ISO-NE experienced notable operational issues. Specifically, the Ontario subregion reported a single occurrence of Firm load loss due to a bulk transmission outage on July 5, 2010. Additionally, hydroelectric capabilities were lower than normal, causing IESO to revise its planning assumptions accordingly for the fall months. The ISO-NE subregion reported five instances of triggered EOPs during the summer. A lack of rainfall caused lower hydrological conditions during the late summer months resulting in the temporary loss of capacity and energy from certain hydroelectric facilities. However, other resources were available

For the PJM subregion, although certain generators needed to limit total run hours due to environmental restrictions, PJM worked closely with asset owners to ensure sufficient run hours during peak load operations. Additionally, the implementation of Load Management, along with Maximum Generation Alerts, Hot Weather Alerts, and EEAs were deemed necessary during the 2010 summer; however, no voltage reductions, public appeals, or Special Protection System (SPS) operations were implemented.

SaskPower, located in the MRO Region, had projected below-normal conditions with near-normal operating regimes. However, above-normal levels were observed, as reservoir levels were higher than normal due to heavy spring rains.

The SPP footprint managed a new all-time summer peak without any significant issues, aside from a continued constrained Acadiana Load Pocket in southern Louisiana. Multiple EEA Level 2 and Level 3 were reported for the SPP RE, continuing the trend in this area for the past 3 years, albeit at much lower levels when compared to the 2009 summer.[6] This constraint will soon be mitigated as transmission improvements are underway in the area with expected completion in mid-2012. The integration of variable resources continues to be an area of focus for the SPP footprint.

SERC entities reported two local area issues that were short in duration and involved loss of non-consequential load. Multiple EOPs occurred during the 2010 summer, caused by various situations, but usually in connection with routine procedures. Two notable events reported by two separate SERC entities included a small control room fire as well as a call for public appeals. Additionally, seventeen Firm interchange transactions were curtailed throughout the summer due to the neighboring system's NERC Transmission Load Relief Procedure (TLR); however, these events did not impact the operating Reserve Margins of areas within SERC. Ongoing transmission projects will help provide long-term reliability benefits to the area and are expected to be complete by mid-2011.

[6] EEA 2 NERC Dashboard: http://www.nerc.com/page.php?cid=4|331|341;
EEA 3 NERC Dashboard: http://www.nerc.com/page.php?cid=4|331|335

WECC encountered two Remedial Action Scheme (RAS) activations during the summer season, both resulting from the interruption of 500kV lines. These transmission issues resulted in the loss of generation in both cases. In addition, an event relating to forest fires in southern California caused a transmission separation between the northern and southern parts of the state.

Several entities also experienced multiple disturbance events during the summer season that resulted in the issuance of an Electric Emergency Incident and Disturbance Report (Department of Energy Form OE-417).[7] A full listing of these disturbances can be found in *Appendix III*.

## Experiences and Recommendations

Although each NERC Region is inherently different, many share similar operating challenges from season to season. Sharing these experiences and subsequent lessons learned throughout 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,[8] which can be targeted to specific stakeholders who may gain value from such information. Below are some of the experiences observed during the 2010 summer.

***Addressing challenges caused by forced and unforced transmission and generation outages***

FRCC, SPP, PJM, Québec, and SERC all emphasized the importance of, and need for close coordination between transmission and generation outages to ensure reliability. This is especially important in situations where significant investment in transmission require planned system outages. PJM has relied on redispatching activities to help control transmission constraints based on load as well as the location, economics and availability of generators throughout the system. Québec indicated the importance of creating new forecasting analyses of system conditions prior to and during the management of scheduled outages. Finally, SPP stressed the need to improve coordination when scheduling the commissioning testing of new units, as well as transmission additions and upgrades. Overall, improved coordination efforts and procedures for all Regions will be necessary to continue addressing these issues before and throughout the next summer.

SERC's diverse topology has led to different approaches from each utility when addressing prolonged high temperatures. These conditions have delayed planned outages that often resulted in subsequent re-scheduling conflicts. Additional areas of focus include identifying constraints, followed by allowing short-term planning and real-time operations to account for these constraints before reaching a state of compromised reliability. Other entities are learning to efficiently validate and communicate expected Demand Response prior to the peak season.

***Improving methods for accommodating high-levels of variable generation***

Regions located in the Midwest have stressed the issue of variable generation and related impacts on the bulk power system. As the total number of wind units continues to increase in the MISO, SaskPower and SPP RE Areas, system operators must ensure that the potential challenges of variability are offset by the availability of conventional units. Despite challenges for operators in forecasting the amounts of wind production, it is still necessary to ensure the economical and secure operation of the bulk power system. SaskPower has noted the benefits of forecasting along with internal unit commitment tools that allow system operators to improve the management of the potential of wind resources.

The SPP RE's Wind Integration Task Force recently submitted a report with findings that the Regional Transmission Operator (RTO) could potentially absorb wind penetration levels of up to 20 percent.

[7] http://www.oe.netl.doe.gov/oe417.aspx
[8] http://www.nerc.com/page.php?cid=5|385

However, this can only be accomplished with significant improvements in both transmission and wind forecasting tools. The report also introduced new efforts to obtain and implement a Region-wide wind-forecasting tool.

The MISO continues efforts to improve its ability to mitigate issues related to adverse conditions through fostering a solid relationship with open communications between the Regional Balancing Authorities. A shared understanding of the policies, combined with procedural tools is also essential in supporting Regional reliability. Finally, the MISO continues to host several events involving working groups and committees to further advance the knowledge base and expertise in planning strategies for subsequent seasons.

***Managing large quantities of long lead-time fossil-based generation***

The New England subregion signified difficulties in managing multiple fossil-based generators that require significantly longer start-times compared to quick-start, peaking generators. This has a direct impact on contingency recovery, and ISO-NE has worked to alleviate this issue by prioritizing the need for accurate demand forecasting to improve scheduling, commitment, and dispatch coordination of area generation. These efforts will help to not only satisfy daily peak demand levels but also increase operating reserve requirements.

## Assessment Areas

Table 2 below offers a brief description of each assessment area. Detailed assessments are provided in the next section.

**Table 2: Assessment Area Descriptions**

| Areas | Area (Sq. Mi.) | Population Served | Peaking Season | Balancing Authorities |
|---|---|---|---|---|
| ERCOT | 200,000 | 22,000,000 | Summer | 1 |
| FRCC | 50,000 | 16,000,000 | Summer | 10 |
| NPCC | 1,233,100 | 55,110,000 | Multiple | 6 |
| ISO-NE | 68,000 | 14,000,000 | Summer | 1 |
| NBSO (Maritimes) | 57,800 | 1,910,000 | Winter | 2 |
| NYISO | 48,000 | 19,200,000 | Summer | 1 |
| Ontario | 415,000 | 13,000,000 | Summer | 1 |
| Québec | 644,300 | 7,000,000 | Winter | 1 |
| MISO | 56,300 | 40,000,000 | Summer | 4 |
| PJM[9] | 168,500 | 51,000,000 | Summer | 1 |
| SaskPower[10] | 251,700 | 1,000,000 | Winter | 1 |
| SERC[11] | 567,200 | 70,000,000 | Summer | 31 |
| Central | 101,000 | 11,670,000 | Summer | 5 |
| Delta | 185,300 | 14,885,000 | Summer | 11 |
| Gateway | 65,500 | 10,335,000 | Summer | 5 |
| Southeastern | 114,400 | 14,215,000 | Summer | 4 |
| VACAR | 101,000 | 18,895,000 | Summer | 6 |
| SPP | 370,000 | 15,000,000 | Summer | 29 |
| WECC[12] | 1,845,000 | 80,894,000 | Summer | 38 |
| CA-MX | 191,000 | 40,127,000 | Summer | 3 |
| SW | 236,000 | 8,605,000 | Summer | 12 |
| RMPA | 202,000 | 5,569,000 | Summer | 2 |
| NW | 1,216,000 | 26,593,000 | Winter | 20 |

[9] Operates in RFC and SERC

[10] Saskatchewan Power Corporation Reliability Coordinator (SaskPower) is a provincial Crown corporation and operates under the legislated mandate and authority of the provincial government of Saskatchewan. SaskPower is the principal supplier of electricity in the province of Saskatchewan, and its obligation is to deliver power in a safe, reliable, and sustainable manner to the province. Under provincial legislation, it has the sole regulatory authority and responsibility for bulk electric reliability in the province.

[11] 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). Additionally, the SERC reporting area monthly peak values were used for the preliminary "actual" 2010 summer peak and were collected from the entities on a non-coincident basis.

[12] WECC subregional boundaries for Seasonal Assessments differ from those used in NERC's Long-Term Reliability Assessments.

# ERCOT

## Demand

The ERCOT Region's preliminary actual peak demand occurred on August 23, 2010 at 65,716 MW, 2.6 percent higher than the forecasted peak of 64,056 MW. The preliminary actual peak was 2.5 percent higher than the day-ahead peak demand forecast for August 23, 2010. This difference was a result of Region-wide temperatures averaging higher than expected during the peak period. Despite the warmer weather, no Demand Response activities were deployed for reliability purposes.

## Resources

The ERCOT Region had 68,413 MW of available capacity during the summer peak and did not experience any reliability concerns during this period due to delays of new units scheduled for initial operations, delays of existing units returning to service after a scheduled outage, or delays of commercial operation of new transmission elements.[13]

## Operational Issues

During the 2010 summer period, no Special Protection System (SPS) operations were used to mitigate any reliability concerns. Additionally, there were no voltage reductions, public appeals, or Firm/Non-Firm interchange transaction interruptions during the 2010 summer season concerning reliability. There was no loss of Firm load due to the non-performance of resources or transmission element outages and no fuel situations affected the availability of resources.

Although two EOPs were initiated, neither occurred during the peak period. On June 23, one generator tripped, leading to the loss of 733 MW of generation; an EEA – Level 1 was issued, lasting approximately 30 minutes. In addition, on August 20, 2010, two units tripped, totaling 1,394 MW, which led to an EEA Level 1 state for approximately one hour. The EOP concluded after additional generation came on-line to maintain the required amount of Responsive Reserves.

The required Contingency Reserve for the ERCOT Region[14] must be at least 1,354 MW, but the ERCOT Region requires at least 2,300 MW of Responsive Reserve for all hours under normal conditions.[15] The projected Operating Reserve for the ERCOT Region for the peak period was 2,381 MW and the actual for the peak period was 2,650 MW, exceeding all reserve requirements.

## Lessons Learned

Despite an especially hot month of August, the ERCOT Region maintained normal operations throughout the summer period as a result of effective coordination between generator and transmission owners and operators, and the ERCOT ISO. The greatest challenges experienced during the 2010 summer were forced outages; however, actions taken by the ERCOT ISO and the Generating Operators ensured that there were no capacity shortages. Although two EEA Level 1 events were experienced, neither lasted more than one hour, during which additional Responsive Reserves were brought on-line to replenish the minimum 2,300 MW reserve requirement level required by ERCOT. No additional reliability considerations affected reliability. Therefore, the ERCOT ISO believes it maintains adequate procedures to address the issues listed above and is prepared for the next summer season.

[13] Available capacity was calculated as the sum of actual generation and Spinning Reserves, not seasonal planned capacity. This amount does not include Non-Spin Reserves.

[14] As defined by NERC standard BAL-002

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

# FRCC

### Demand

The FRCC Region forecasted a non-coincidental peak demand of 46,034 MW, compared to an actual peak demand of 45,540 MW.[16] The peak demand occurred on August 19, 2010 and was similar to the day-ahead (coincidental) peak demand forecast of 45,518 MW. During the actual peak demand which occurred in the afternoon, approximately 3 MW of Demand Response were activated.

### Resources

There were no delays in the initial operation of new units and/or transmission facilities and no delays were experienced that impacted reliability in returning units to service following scheduled maintenance. During the 2010 summer peak demand period, some planned unit outages were re-scheduled in order to provide the complete availability of Regional generation capacity necessary to meet anticipated system demands within the FRCC State Capacity Emergency Coordinator (SCEC) footprint.

### Operational Issues

The FRCC-SCEC issued five Capacity Advisories during the 2010 summer.[17] The SCEC also issued capacity advisories prior to the time periods where excessively hot temperatures were anticipated. For 2010, on the peak day, the Region was not in a capacity advisory condition. There was ample capacity available and therefore, no EOPs were needed to maintain system reliability and serve the peak demand. With respect to available generation capacity, there were no reliability concerns with the operation of the three gas pipelines serving the Region.

During the peak demand day, the FRCC's largest nuclear plant was not available due to an extended maintenance outage. However, the Region still had sufficient operable capacity to meet the peak demand. On this day of peak demand, the Operating Reserve was 7,832 MW[18], which equates to an Operating Reserve Margin of 17.2 percent, exceeding FRCC's most severe single contingency of 930 MW.

### Lessons Learned

Due to the peninsular nature of the FRCC Region, close coordination of transmission and generation outages is imperative to ensure the collective reliability of the Region. The FRCC Region continues to improve its coordination efforts and address emerging issues through the work of its standing committees and their subordinate subcommittees, working groups, and task forces.

[16] Forecasted peak demand values were consolidated by the FRCC State Capacity Emergency Coordinator (SCEC) from the forecasted peaks of the individual Balancing Authorities (BAs) to obtain a single forecasted Regional value for the next day. The peak demand assessed within this assessment compares the Regional forecast (seasonal basis) to the general, day-ahead forecast compiled by the SCEC.

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

[18] Total resources are obtained by adding the available day-ahead capacity (51,088 MW) and unused available CCDR (2,284 MW) that are projected for system peak. The Reserve Margin, for NERC purposes, is calculated by reducing total resources by the preliminary "actual" peak (45,540 MW provided by the FRCC RC) and dividing again by the preliminary "actual" peak.

# MISO

### Demand

The MISO Reliability Coordinator's peak demand of 108,907 MW and 107,188 MW are based on the instantaneous and the hourly-integrated average value, respectively in the MISO footprint. However, to provide consistency with this year's reporting methods, the actual peak demand of 114,516 MW is based on one Regional value from FERC's daily report (based on the MISO footprint) and is used for further calculations in this report. This actual peak demand is an hourly-integrated average value.

The Region's actual peak demand of 114,516 MW occurred on August 10, 2010 (hour ending 16:00 EST).[19] This peak demand was five percent higher than the seasonal, simultaneous forecasted peak of 109,009 MW[20] The day-ahead peak demand forecast of 112,494 MW was 2,022 MW (1.8 percent) lower than the actual peak demand of 114,516 MW. The footprint's all-time summer peak demand of 129,647 MW occurred on July 31, 2006 and was significantly higher than the 2010 summer peak demand. Possible reasons for the large disparity could be related to the current economic recession or to membership changes in the MISO footprint since 2006.

The 2010 summer was one of the warmest in recent years. During August, the footprint experienced persistently high temperatures and relative humidity with variable precipitation. The average load-weighted Heat Index[21] exceeded 90° F for 79 hours during the peak month, leading to the declarations of several Hot Weather Alerts. In contrast with August 2009, which was historically one of the coolest, the Heat Index was above 90°F for only nine hours. Hourly Real-Time demand exceeded 100 GW for 64 hours in August 2010, while only one hour was slightly above 90 GW in August 2009.[22] The MISO currently separates demand resources into two separate categories, Interruptible Load[23] and DCLM,[24] neither of which were deployed during the 2010 summer season.

### Resources

During the 2010 summer season, the MISO experienced no delays to new unit initial operation, to existing units being brought back into service after scheduled outages, or to expected commercial operation of new transmission facilities that caused any reliability concerns.

### Operational Issues

There was no loss of Firm load resulting from any non-performing bulk power system resource, or from an outage of any bulk transmission facility. Additionally, no fuel supply or delivery situations affected resource availability. There were three hot weather alerts declared for the market footprint on August 9, 11 and 12. Conservative operations announcements were made on August 10 and 11. A maximum generation emergency alert was declared in northeast Ohio, due to generation loss in the area. Additionally, there were multiple forced outages on PJM transmission; however, no EOPs were deployed to maintain system reliability in the MISO footprint.

The MISO did not activate Interruptible Load or Direct Controlled Load Management DCLM during the

[19] FERC daily reports.

[20] MISO's FERC daily report forecast.

[21] Measures the combined effect of temperature and humidity.

[22] http://www.midwestmarket.org/publish/Folder/13b9ea_1265d1d192a_-7db50a48324aa?.

[23] 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.

[24] Magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving."

2010 summer. No reported Special Protection Systems (SPS) or Remedial Action Schemes (RAS) operated and no voltage reductions or public appeals were implemented during peak demand periods to maintain the Operating Reserve Margin. Additionally, there were no Firm interchange transactions interrupted to maintain the Operating Reserve Margin. The actual peak demand day Operating Reserve was 6,723 MW (6.7 percent) and met the Operating Reserve Margin requirement of 2,482 MW.

**Lessons Learned**

One of the most important challenges to operating the bulk power system in the MISO is related to the integration of wind. Registered wind capacity and wind generation have grown in the MISO market consistently for the last three summers. This trend is expected to continue due to state Renewable Portfolio Standards (RPS) and potential Federal mandates. Due to the intermittent nature of wind, there is no way to guarantee the availability of wind capacity during peak demand periods. Wind output during the 2010 summer peak demand hour ranged from 1,675 MW to 1,875 MW. During the same hour, an estimated 185 MW of wind output was temporarily curtailed to manage local congestion. Additionally, during the three days of hot weather mentioned in this assessment, the wind output ranged from as high as 2,500 MW to less than 50 MW. As wind resources begin to comprise a greater portion of the MISO footprint capacity, this variability poses several potential issues. For additional information wind conditions in the MISO, please see Appendix IV.

Prior operating experiences have aided the MISO in dealing with the unexpected weather conditions observed during the 2010 summer. The MISO continually strives to improve its ability to mitigate issues related to adverse operational conditions by fostering a solid partnership with the Balancing Authorities and Local Balancing Authorities in the Region through the use of open communication, a shared understanding of the policies, and procedural tools that support Regional reliability. The MISO hosts a number of stakeholder forums to help maintain reliability of the wholesale bulk power system including the: Reliability Subcommittee, Operations Working Group, Reliability Procedures and Documents, Reliability Authority website, and the Midwest Contingency Reserve Sharing Group. Operating experiences from the past summer will help build the knowledge base and refine the expertise in planning preparations for subsequent seasons, especially with wind comprising a greater portion of the MISO footprint capacity every year.

# NPCC

## Demand

**ISO-NE:** The ISO-NE subregion forecasted a 2010 summer peak demand of 26,618 MW. The preliminary actual peak was 27,154 MW,[25] occurring on July 6, 2010, which equates to a 536 MW (or 2.0 percent) difference.

The 2010 summer peak demand forecast accounts for a reduction of approximately 572 MW of "passive" or "non-dispatchable" Demand Response resources embedded within the summer peak demand forecast of 27,190 MW. The day-ahead peak demand forecast was 26,800 MW[26] As noted above, the preliminary actual peak demand of 27,154 MW occurred on July 6, 2010 (hour ending 15:00 EST)[27] with reported temperature and dew point of 95°F and 67°F, respectively,[28] amounting to a 354 MW (1.3 percent) difference between day-ahead and the preliminary actual value.

New England experienced continuously hot weather conditions during the majority of the 2010 summer.[29] Demand Response was not activated at the time of peak demand, however, approximately 1,190 MW of dispatchable Demand Resources were in place and ready for activation.

Some specific highlights concerning New England's 2010 summer weather and the resultant electricity consumption are shown below:

- July 2010 was the second-hottest July in New England since 1960.
- New England's all-time electricity consumption for one month was recorded in July at 13,386 gigawatt-hours (GWh). The previous one-month consumption record was set in July 2006, with 13,365 GWh of electricity consumed.
- Overall electric energy use in June, July, and August totaled 36,864 GWh, ranking the 2010 summer in third place behind the 2005 summer (38,150 GWh) and the 2006 summer (37,076 GWh).
- A new peak demand record for the month of May was set on May 26, 2010 at 22,817 MW.
- A new peak demand record for the month of September was set on September 2, 2010 at 25,894 MW.
- During one heat wave, two new "Top-10 Demand Days" were also recorded: July 6, 2010 (27,154 MW) and July 7, 2010 (26,508 MW).[30]

During the summer period, Demand Response resources were only dispatched once, on June 24, 2010, as contingency reserves for reliability purposes. In response to a pending capacity deficiency, ISO-NE triggered the dispatch of approximately 670 MW of Real-Time Demand Response (RTDR) at 13:55 EST on June 24, 2010. Another 520 MW of Real-Time Emergency Generation (RTEG) was available for dispatch, but was not triggered during this event.

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[25] Compiled from preliminary meter readings and reported the next morning. The weather-normalized 2010 summer peak demand was 27,075 MW

[26] The second posting of the ISO-NE Morning Report, time stamped at 08:10:15 EDT on 07/06/10

[27] The second posting of the ISO-NW Morning Report, time stamped at 08:19:00 EDT on 07/07/10

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

[29] May through September.

[30] These values are preliminary "actuals" taken from the (ISO-NE) next day's Morning Report.

During the 2010 summer peak demand day the actual peak Operating Reserve were 2,721 MW compared to the Operating Reserve Requirement of 2,073 MW, providing 648 MW of surplus to satisfy the Operating Reserve Requirements for the peak hour of the day.

**Maritimes**: The Maritimes subregion peak demand load during the 2010 summer was calculated by summing each sub-area's actual peak demand.[31] The actual peak demand of 3,497 MW was reached on September 1, 2010 (hour beginning 07:00 ADT). The actual peak was 381 MW lower than the seasonal forecasted peak demand of 3,878 MW, but 192 MW higher than the day-ahead forecasted peak of 3,305 MW. The Maritimes subregion did not experience any unexpected extreme or adverse weather conditions, and because no summer Demand Response Program (DRP) was deployed since none exists in the subregion during the summer.

**NYISO:** NYISO forecasted a peak demand of 33,025 MW for the 2010 summer while a similar actual peak demand of 33,425 MW was reached on July 6, 2010 (hour beginning 16:00 EST). The day-ahead forecast was 32,675 MW, which was 750 MW (2.2 percent) lower than the actual peak demand. Active Demand Response activities reduced actual peak demand by 500 MW. Using the adjusted actual load of 33,952 MW as the basis of comparison, the day-ahead forecast was lower than the actual demand by 1,277 MW (-3.8 perecnt). The composite statewide maximum temperature forecast for the day of the peak demand was 95°F, while the actual statewide maximum temperature was 97°F. Based on an approximate demand/temperature ratio of 550 MW per degree, a -2° error in the temperature forecast directly relates to approximately 1,100 MW (about 90 percent) of the adjusted forecast demand error of 1,277 MW.

The daily maximum 17-station composite temperature was at 85°F on July 2 (near the monthly average of 84.5°F). During the following four days, a heat wave caused temperatures to reach 96.6°F on July 6 (the day of the NYBA system peak). This placed the actual 17-station composite temperature-humidity index at the 86th percentile, whereas the expected value was at the 50th percentile.

Approximately 500 MW of Demand Response was activated at the time of seasonal peak demand. The NYISO invoked Special Case Resources and emergency Demand Response resources from its control center, which contributed an estimated 450 MW of demand reductions. The local utility, Consolidated Edison, activated an air conditioning duty cycle program that also contributed an estimated 25 MW of demand relief. Finally, public appeals along with the impacts of other programs activated by the New York Power Authority contributed an estimated 25 MW of additional demand reductions.

**Ontario**: The Independent Electricity System Operator (IESO) directs the operation of the Regional power grid and administers the electricity market for Ontario. The Ontario Region reported normal weather peak and day-ahead forecasts of 23,498 MW and 24,844 MW, respectively for the 2010 summer. These values were lower than the actual summer peak demand of 25,075 MW, occurring on July 8, 2010 (hour ending 15:00 EST), and were about 2,000 MW lower than the all time Ontario peak demand of 27,005 MW (August 2006). On a weather-normalized basis, the 2010 summer peak demand was 23,916 MW.

As indicated by the direction of the weather correction, the peak day temperatures were much warmer than normal. July 8, 2010 was hot and humid, with the temperature topping 33°C (91°F) and the humidity index reaching 44°C (111°F).[32] The peak demand occurred on the sixth consecutive day when temperatures topped 30°C (86°F) and humidity levels increased with each passing day. At the time of

[31] New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator.

[32] As measured at Toronto Pearson airport.

peak demand, there were 111 MW an economically based Demand Response activated per provincial conservation and Demand Response initiatives.

**Québec**: The load serving entity in Québec is Hydro-Québec Distribution (HQD), represented as the single entity that conducts load forecasts for its internal demand (with no demand aggregation). From this peak forecast information, TransÉnergie[33] issued annual internal demand forecasts for the Balancing Authority subregion, with accompanying monthly, weekly, daily, and hourly forecasts for System Control's real-time use. The actual monthly peak internal demands are determined by the Statistics Unit at System Control and Operations (Contrôle et exploitation du réseau). Demand statistics were presented for the Balancing Authority subregion.

The actual peak demand for the 2010 summer reached 22,092 MW and occurred on July 8, 2010 (hour ending 12:00 EDT). This was 1,415 MW higher than the forecasted peak demand of 20,677 MW, which was expected to occur in September. Although the subregion typically observes lower peak demands in June, July, and August, with slight demand pick-up in September, the 2010 summer had unusually heavy July, August and September peaks. The explanation for the difference between the forecast and the actual demand can partially be attributed to additional industrial demand, particularly the aluminum sector. The higher than forecasted peak demand also corresponded with two heat waves in early July and late August that drove-up air conditioning load.

July 8, 2010 was the last day of a five-day heat wave when temperatures reached 34 °C (93°F). A second heat wave was responsible for setting monthly peak demands of 31$^{st}$ and 1$^{st}$ of August and September. Demand Response is not available in the Québec area during the summer.

### Resources

NPCC areas experienced no reliability concerns due to delays to new resources expected to be commercialized prior to, or during the 2010 summer. New England reported that the recent commercialization of several new gas sector projects has resulted in increased access to new gas supplies, as well as improved deliverability throughout the subregion. Because of these (and other) infrastructure enhancements, lower natural gas prices, and the fact that a majority of New England's generation fleet is gas-fired, there were no major fuel supply constraints reported within the generation sector, and all system operations were managed throughout the 2010 summer.[34]

Regarding initial operations of new units and generation outages, the Thorold Cogeneration plant in the Ontario subregion delayed its initial operation until after the summer. Additionally, the New England subregion experienced 1,100 MW of outages from early May to late fall associated with a pumped-storage station.[35] Neither instances affected reliability.

NPCC areas did not experience any reliability concerns due to delays in achieving commercial operation of new transmission facilities prior to, or during the 2010 summer, and because of this, no special guides or operating procedures were necessary to maintain system reliability.

### Operational Issues

The Maritimes, New England, New York, and Québec subregions reported no loss of Firm load due to the non-performance of any bulk power system resource or bulk transmission facility outage.

[33] Acting as Reliability Coordinator

[34] 2010 summer capacity ratings show 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.

[35] These values are preliminary "actuals" taken from the (ISO-NE) next day's Morning Report.

ISO-NE reported five instances of triggered EOPs during the summer primarily due to higher than expected temperatures and humidity, as well as generator forced outages and reductions. Details on each EOP are listed below:

1. On Sunday, May 2, 2010, ISO-NE implemented EOPs system-wide in New England as higher than expected temperatures and humidity resulted in the peak demand exceeding the forecast demand by more than 1,000 MW. The demand deviation was caused by the combination of higher afternoon temperatures; significantly higher afternoon dew points and lack of thunderstorm generated cloud cover.
2. On Wednesday, May 26, 2010, ISO-NE implemented EOPs system-wide in New England as higher than expected temperatures and humidity resulted in the peak demand exceeding the forecast demand by approximately 1,500 MW. Boston, MA temperature was 93° F, 15 degrees above the initial forecast with a dew point that was 4 degrees higher than the initial forecast. Temperatures in Hartford, CT reached 98° F, which was 6 degrees higher than the initial forecast.
3. On Thursday, June 24, 2010, ISO-NE implemented EOPs due to approximately 1,465 MW of generator forced outages and reductions that occurred throughout the day. Temperatures in Boston, MA and Hartford, CT ran close to the forecast and New England demand tracked within 100 MW of the demand forecast through 14:00. After 14:00, Regional demand dropped off sharply due to a combination of Demand Response implementation and strong thunderstorms moving through New England.
4. On Monday, July 5, 2010, a significant under-forecast of New England's demand resulted in a capacity deficiency causing ISO-NE to implement EOPs. Temperatures in Boston, MA and Hartford, CT ran close to the initial forecast, subsequently removing weather as a contributing factor. Large temperature swings over the prior summer months coupled with the Independence Day Business Holiday being observed on Monday July 5, skewed the New England demand forecast models. These deviations, which resulted in an under-forecast of demand exceeding 1,400 MW, were not recognized early within the Day-Ahead process but were eventually mitigated in real-time by ISO-NE Control Room staff.
5. On Monday, August 9, 2010, ISO-NE implemented EOPs to manage a deficiency in thirty-minute operating reserve. Entering the day, the operating plan indicated an operating reserve surplus of 378 MW. The combination of demand being greater than forecast and numerous in-day generation outages and reductions resulted in a deficiency in thirty-minute operating reserve. Higher temperatures with less cloud coverage resulted in the actual demand exceeding the forecast demand by 1,004 MW. During the day, generation outages and reductions totaled 844 MW and as a result, a deficiency of thirty-minute operating reserve occurred.

In addition, New England's extended heat and subsequent lack of rainfall created low hydrological conditions during the late summer months.[36] This situation resulted in the temporary "loss" of capacity and energy from some hydroelectric facilities. However, this temporary loss was offset by other system resources.

The Ontario subregion reported one occurrence of Firm load loss due to a bulk transmission outage on July 5, 2010 when a phase-to-ground fault caused a 230 kV oil breaker to fail explosively at Manby

[36] EOPs in New England primarily consisted of triggering ISO-NE Operating Procedure #4 – Action During A Capacity Deficiency (OP4).

Transformer Station, triggering five subsequent faults and removing an entire 230 kV to 115 kV transformer station from service.[37] The cause of the failure of the breaker was deemed to be an insulation breakdown due to a high particulate count in the oil. The breaker had been in service for the past 32 years and was not a candidate for replacement. It was determined to be in adequate condition based on previous maintenance and sampling schedules. Approximately 1,550 MW of Firm load was interrupted, 902 MW of which was removed from service by configuration. The remaining 648 MW of non-consequential load was triggered by the operation of customer-owned under-voltage protection within surrounding local distribution centres. There was no generation loss as a result of the breaker failure. Power flows on interconnections to Michigan and New York experienced increases of 725 MW and 690 MW respectively. Flows were well within interface capabilities. Intertie schedules were restored to pre-contingency levels within 12 minutes. System voltages were restored to normal within 10 minutes. With the exception of one load distribution station and several feeders at another, all load removed by the contingency was restored through load transfers in under two hours from the time the incident occurred. The remaining load was restored within 3 hours and 35 minutes after the initial trip.

Ontario also experienced hydroelectric capabilities that were 16 percent to 22 percent lower than normal during the summer months due to lower water levels. This prompted the IESO to revise its planning assumptions accordingly for the fall months. With hydroelectric output returning to normal conditions, the hydroelectric capability assumptions were reverted back to their historical median values at the time of weekday peak for future adequacy assessments.

### Lessons Learned

The ISO-NE subregion emphasized the importance of managing the large quantity of long lead-time (start-time) fossil-based generation and how it compares to quick-start, peaking generation, with respect to contingency recovery. To address this issue effectively, ISO-NE makes accurate demand forecasting a priority, followed by the scheduling, commitment, and dispatch of generation to satisfy both daily peak demand levels and operating reserve requirements.

The Québec subregion experienced no significant operating or reliability issues during the 2010 summer as the subregion observed lower load conditions on Hydro-Québec's system, which helped to facilitate necessary generation and transmission maintenance. While problems of generation adequacy are rare, more attention should be directed at addressing generation and transmission scheduled outages. The subregion also highlighted the importance of performing thorough analyses of forecasted system conditions when managing scheduled outages. The assessed information should consider equipment expected to be out of service, and include multiple weather forecasts and other operating methods, such as contingency analysis tools. TransÉnergie has a permanent weather forecasting staff providing information to System Control on an ongoing basis. The preparation for the next summer will be similar to past summers and no additional reliability considerations need to be addressed at this point.

[37] Details about this incident can be viewed at the IESO web site under Reliability Incident Reports at: http://www.ieso.ca/imoweb/pubs/ircp/IESO_REP_0670-Manby_Incident_20100705.pdf.

# PJM

### Demand

Actual peak demand of 136,553 MW was higher (0.9 percent) than the annual peak forecast[38] of 135,380 MW. The actual peak demand was also slightly higher (0.6 percent) than the day-ahead forecast of 135,784 MW. Normal projected summer weather was observed during the peak period and no Demand Response was used on the Region's peak day.

### Resources

During the 2010 summer season, the PJM RTO experienced no delays to new unit initial operation, to existing units being brought back into service after scheduled outages, or to expected commercial operation of new transmission that caused any reliability concerns.

### Operational Issues

PJM experienced no loss of Firm demand due to the non-performance of a bulk power system resource, or due to a bulk transmission outage. PJM initiated redispatching activities to control transmission constraints based on load as well as the location, economics and availability of generators throughout the system. Additionally, environmental restrictions limited total run-hours on some combustion turbines, but these limits were not met and PJM worked closely with asset owners to ensure sufficient run hours were available during peak load operations.

The implementation of Load Management, along with the following alerts, were implemented at times throughout the summer peak season:

- The Maximum Emergency Generation Alert;
- Hot Weather Alert; and
- NERC's Energy Emergency Alerts (EEA 1 and EEA 2).

PJM did not implement voltage reductions, initiate public appeals, or implement any Special Protection System (SPS) operations. Additionally, PJM experienced no TLR Level 5a reallocations or Level 5b curtailments of Firm demand transactions. Actual Operating Reserves were 11,502 MW, 26 percent higher than Required Operating Reserves of 8,523 MW on the day of peak demand.

### Lessons Learned

No events occurred that resulted in any special lessons learned in 2010; however, PJM emphasizes that outage coordination is a key factor that must continue to be managed to ensure reliable operations, and is an issues that will continue to be applied. Significant investment in transmission requires close coordination with transmission and generation outages to ensure reliable operations during system outages. These issues will be considered in forthcoming seasons.

[38] Dated January 2010

# SaskPower

### Demand

The actual summer peak demand (instantaneous) of 2,770 MM occurred on July 26, 2010 (hour ending 16:00).[39] The actual peak demand was 161 MW (5.5 percent) less than the forecasted seasonal peak demand of 2,931 MW, and 60 MW (2.2 percent) more than the day-ahead hourly peak demand forecast of 2,710 MW. No Demand Response was deployed during the period of peak demand when Saskatchewan was exporting 75 MW and importing 42 MW.

### Resources

During the 2010 summer season, SaskPower experienced no delays to new unit initial operation, to existing units being brought back into service after scheduled outages, or to expected commercial operation of new transmission that caused any reliability concerns.

### Operational Issues

SaskPower did not experience any significant operating issues during the 2010 summer. As expected, Saskatchewan reservoirs were at below-normal conditions, but operated at near-normal regimes. As conditions improved due to heavy spring rains, reservoir levels rose to above-normal levels.

Actual Operating Reserve in Saskatchewan at time of the summer peak demand was 321 MW,[40] which included 128 MW of spinning reserve. Saskatchewan's Contingency Reserve and Spinning Reserve requirements were 281 MW,[41] and 112 MW,[42] respectively; therefore, all reserve requirements were met.

### Lessons Learned

With the increased penetration of wind and its variability in energy production in Saskatchewan, it is important for system operators to ensure conventional units are readily available to offset the potential impacts of this variability. Forecasting the amount of wind production to be used during the day is a demanding task. Operators must observe wind production on an hourly basis to ensure the system is operating both economically and securely. In order to accomplish these goals, a third party consultant service was used to provide next-hour to next-day wind forecasts. The use of these wind forecasts, combined with internal unit commitment tools, allowed system operators to manage wind resources along with their potential intermittent production.

[39] All demand and generation values reported are based on the SaskPower footprint.
[40] Includes both non-spinning and spinning units available at that time.
[41] Based on the Region's largest single contingency.
[42] 40 perecnt of its largest single contingency.

Area Self-Assessments

# SERC

### Demand

The preliminary “actual” 2010 summer peak demand for the SERC reporting area was 184,205 MW, recorded in August, which exceeded the forecast total aggregate internal demand of 181,570 MW by 2,635 MW (1.5 percent.) Above-normal temperatures throughout the 2010 summer contributed to new all-time system peaks by some of the reporting entities; however, economic conditions and regular periods of rainfall in other areas resulted in an overall reduction in energy demands.

The day-ahead peak demand forecast for the SERC reporting area was 180,435 MW. This is 3,770 MW (2.1 percent) lower than the preliminary actual 2010 summer peak demand. Previous peak demands were set during August 2007. The use of various software and forecasting methods resulted in projections that were consistent with the actual peak.

Many of the SERC reporting area entities experienced periods of above-normal temperatures and below-normal rainfall. However, certain areas experienced more rainfall than normal, which resulted in minimal temperature buildup and decreased demand. Subsequent reports also indicated pockets of abnormally dry areas within the SERC Region and highlighted northern Louisiana and much of Arkansas as exhibiting severe or extreme drought conditions.[43] Despite these isolated drought conditions, most of SERC did experience near or above-normal rainfall. Please see Appendix IV for additional information. Approximately 253 MW of Demand Response and other programs[44] were implemented during the 2010 summer period of peak demand. This represents 4.6 percent of the 5,517 MW forecasted as available.

### Resources

During the 2010 summer season, SERC experienced no delays to new unit initial operation, to existing units being brought back into service after scheduled outages, or to expected commercial operation of new transmission that caused any reliability concerns.[45] One generator was put into service in mid-June, and while initial operation of the unit was delayed,[46] it caused no reliability concerns and was available for most of the summer period.

### Operational Issues

SERC entities reported two local area issues that were short in duration and involved loss of non-consequential load. One issue occurred during planned infrastructure improvements and did not impact the reliability of the bulk power system. The second issue was an unexpected outage that resulted in a real-time overload on a 115 kV line. In order to relieve this condition, load was shed and then restored once the line was repaired and returned to service. No restoration issues were encountered, and the utility serving this area is currently in the design and routing phases of a planned project to construct a new 230 kV transmission line. This project is scheduled to be complete in 2012 and includes the installation of an autotransformer.

During the 2010 summer period, utilities within the SERC reporting area did not experience any fuel situations that influenced resources and no Special Protection Schemes (SPS) or emergency Remedial Action Schemes (RAS) were deployed to mitigate significant reliability issues.

Several EOPs were initiated during the 2010 summer for various situations, usually related to routine procedures, such as tropical storm or hurricane preparation, generation reduction plans during peak

[43] *The North American Drought Monitor* report observed on August 31, 2010.
[44] Specific programs included air conditioning control, Interruptible Loads, and Demand Response automation.
[45] Utilities within the SERC reporting area rarely schedule generation or transmission outages during summer peak periods.
[46] In-service data was originally scheduled for the first quarter of 2010.

days, or generation re-dispatch events. Two notable events did occur during the 2010 summer. The first event involved a fire in a control room resulting in the operators being relocated to the backup control center. The second involved the initiation of public appeals in the Acadiana Load Pocket (ALP), due to high demands and transmission line loading conditions.

Regarding the second event, a joint project between three transmission owners in the Acadiana Load Pocket area is currently in progress to construct new 230 kV facilities to continue to provide long-term reliability benefits to the area. These projects involve the combined efforts of both SPP and SERC-registered entities working together to complete two phases. The completion of the first phase (Phase 1) is expected during the 2011 summer.

Seventeen Firm interchange transactions were curtailed between early July and mid-August due to the neighboring system NERC Transmission Load Relief Procedure (TLR).[47] None of the Firm interchange transactions curtailed had an impact on the Operating Reserve Margins of the SERC report areas during the 2010 summer.

There were no reported issues in meeting any existing operating reserve requirements for the 2010 summer peak. Please see the SERC Operating Reserve table in Appendix I.

### Lessons Learned

The challenges to operating the bulk power system within the SERC reporting area during the 2010 summer were generally reported as being expected by entities. The prolonged extreme temperatures experienced during the summer months created the most common challenge to reliably operate the system. The diversity in topology and entity size led to different approaches from each utility when addressing prolonged high temperatures. While certain entities highlighted certain constraints to be monitored, others relied on daily, weekly, and seasonal preparations that encountered no adverse conditions related to reliability. Other ongoing challenges are listed below:

- High north-to-south transmission flows
- Inspection of aging infrastructure and vegetation management
- Managing merchant interconnections
- Optimizing the use of Demand Response.

Regarding specific lessons learned, SERC entities reported only normal feedback pertaining to existing policies and procedures. Entities consistently cited existing procedures and plans as the basis for reliable bulk power system performance. Feedback to the existing processes of the entities did highlight an emerging issue with shrinking planned-outage time periods. Higher than normal temperatures created delays in planned outages, that were subsequently rescheduled when practical, but often resulted in scheduling conflicts. Additional areas of focus included identifying constraints, and allowing short-term planning and real-time operations to account for these constraints before reaching a state of compromised reliability. Other entities are learning to efficiently validate and communicate expected Demand Response prior to the peak season.

[47] http://www.nerc.com/files/IRO-006-4.pdf

# SPP

## Demand

The SPP RE footprint experienced a peak demand of 53,146 MW on August 11, 2010, lower than the forecasted peak of 54,974 MW.[48] The peak demand established a new all-time summer peak for the footprint, exceeding the previous peak of 50,898 MW (August 2008).[49] The 2010 peak demand represents an average annual load growth of 2.2 percent. Although there is some minimal amount of Demand Response in the SPP RE footprint, widespread use did not occur during the 2010 summer.

## Resources

There were some reliability concerns caused by commissioning testing of two new generation resources in the SPP RE footprint. The Iatan #2 unit north of Kansas City, MO performed testing throughout the summer months that exacerbated existing transmission constraints from north to south along the 345 kV paths around and onto the 161 kV paths into the Kansas City area. Additionally, the Plum Point generator in the east part of the footprint, near Osceola, AR, also performed commissioning testing throughout August, exacerbating transmission constraints on the 161 kV transmission systems in northern Arkansas and southern Missouri. These transmission constraints were mitigated through the implementation of standard congestion management processes and therefore, no significant measures were needed during the testing process. Both new units were able to complete their required commissioning tests and became fully commercial during the fall of 2010.

## Operational Issues

No loss of Firm load occurred during the summer due to non-performance of generation nor were there any fuel issues that affected generation. There were no EOPs used to maintain reliability. Demand Response was not used to provide contingency reserves for reliability purposes.

The Acadiana Load Pocket, located in southern Louisiana continued to be constrained as the transmission improvements are being under construction. The City of Lafayette, CLECO, and Entergy are working to construct these additions and upgrades, which will be completed during the 2012 summer. SPP RE continued to coordinate operating plans with the operating entities in this area. This coordination allowed for a significant reduction in Transmission Loading Relief (TLR)-5[50] activity and Energy Emergency Alert (EEA)[51] events in the 2010 summer season as compared to a year earlier. However, the integration of intermittent resources, especially wind, continues to create challenges within the SPP RE footprint.

There were no capacity emergencies in the SPP RE footprint and the SPP RE Reserve Sharing Group maintained the required reserve obligation while providing necessary assistance throughout the summer.

## Lessons Learned

The most significant transmission challenge during the 2010 summer involved the 345 kV corridor and 161 kV system north of Kansas City, MO. The commissioning testing of the new Iatan 2 generating unit, along with heavy north to south transactions across the country resulted in significant congestion along this corridor. Several transmission upgrades were put in place prior to the Iatan unit coming online and additional upgrades have occurred since the 2010 summer. A number of other transmission additions

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[48] This value applies to the SPP footprint, which includes Balancing Authorities in SPP, SERC and MRO.
[49] The 2008 peak listed here is adjusted to correspond to SPP's current RC footprint membership.
[50] http://www.nerc.com/files/IRO-006-4.pdf
[51] http://www.nerc.com/page.php?cid=5%7C65

and upgrades are planned in upcoming years. However, this transmission corridor represents a border area between SPP RE, TVA, and the MISO Regions, and this added complexity from congestion in this area requires additional coordination to properly manage these challenges. All parties were able to perform the needed coordination and the area remained secure throughout the summer.

Integration of intermittent resources also continued to be a significant challenge within the SPP RE footprint. The SPP RE Wind Integration Task Force recently submitted its final report. Results included a determination that the RTO can absorb wind penetration levels of up to 20 percent; however, significant transmission improvements are required to support that density. Additionally, improved wind forecasting tools are needed. Due of this finding, a project is currently underway to obtain and implement a Region-wide wind-forecasting tool.

# WECC

## Demand

Subregions within the Western Interconnection experienced brief periods of record high temperatures with corresponding increases in demand. Despite this warmer weather, WECC's overall peak demand on August 25 was 3.3 percent less than the seasonal forecast. This could be partially attributed to the continued slow economic recovery that offset what would have been weather-related demand increases.[52]

The day-ahead peak demand forecast was 145,387 MW, 1.3 percent greater than the actual (non-coincidental) peak demand of 143,511 MW. WECC and the individual reporting areas' day-ahead forecast and actual peak demand are reported Appendix II.

## Resources

During the 2010 summer season, WECC experienced no delays to new unit initial operation, to existing units being brought back into service after scheduled outages, or to expected commercial operation of new transmission that caused any reliability concerns.

## Operational Issues

Regions within WECC experienced loss of Firm load due to the non-performance of one or more bulk power system resources. Alberta residents experienced a loss of Firm load on June 1, 2010 when a lightning strike caused the Alberta transmission system to separate from the Western Interconnection and one minute later, 250 MW of generation tripped at Sheerness due to a suspected problem in the generator unit control system. The combined resource loss resulted in the tripping of 37 MW of Non-Firm demand and 549 MW of Firm demand due to under-frequency load shedding. An additional 114 MW of frequency-sensitive load was also lost. Service to all loads was restored within about an hour.

A fuel interruption also occurred in the WECC Region when Northern Baja California, Mexico experienced a Firm-load loss of 48 MW when low gas pressure caused the loss of 563 MW of combined cycle generation at the Presidente Juarez plant. The gas service interruption was due to an uninterruptible power supply failure affecting the gas supplier's programmable logic controller that controlled a natural gas supply valve at the plant.

WECC experienced two routine Remedial Action Scheme (RAS) activations during the summer season. On July 22, 2010, 87 MW of Non-Firm industrial load tripped because of under-frequency, due to the loss of the Alberta-British Columbia 500 kV tie line and the resulting separation of Alberta from the Western Interconnection. On September 27, 2010, the loss of two 500 kV lines between California and Oregon resulted in the loss of 2,529 MW of Northwest generation and 1,005 MW of California Department of Water Resources Non-Firm pump load. Subsequently, electrical service to 63 MW of Non-Firm agricultural pump load and 532 MW of Non-Firm air conditioning load was interrupted in southern California. The transmission line outage was attributed to a small fire located on the Round Mountain-Table Mountain corridor.

Finally, WECC experienced several events during the summer season that resulted in the issuance of an Electric Emergency Incident and Disturbance Report (Department of Energy Form OE-417; Please see Appendix IV for more details). The first event involved the issuance of a public appeal for energy

[52] The peak demand, reserve, and outage values presented in this assessment are recorded daily and extracted from the NERC Situational Awareness Morning Report, and from the WECC Interconnection Daily Status Report that is posted Monday through Friday, except holidays, on WECC's web site.

conservation. Response to that appeal, which occurred in July in northern Utah, did not significantly affect Operating Reserve Margins. Two of the events presented in the Form OE-417 involved system conditions that significantly affected transfers within WECC. In addition to the September 27, 2010 event, a second event occurred on July 29, 2010, when forest fires in southern California caused a transmission separation between northern and southern California, resulting in an "open loop" transmission configuration within WECC and the interruption of service to 518 MW of interruptible load in southern California.

### Lessons Learned

There were no new or unexpected reliability issues identified during the summer season.

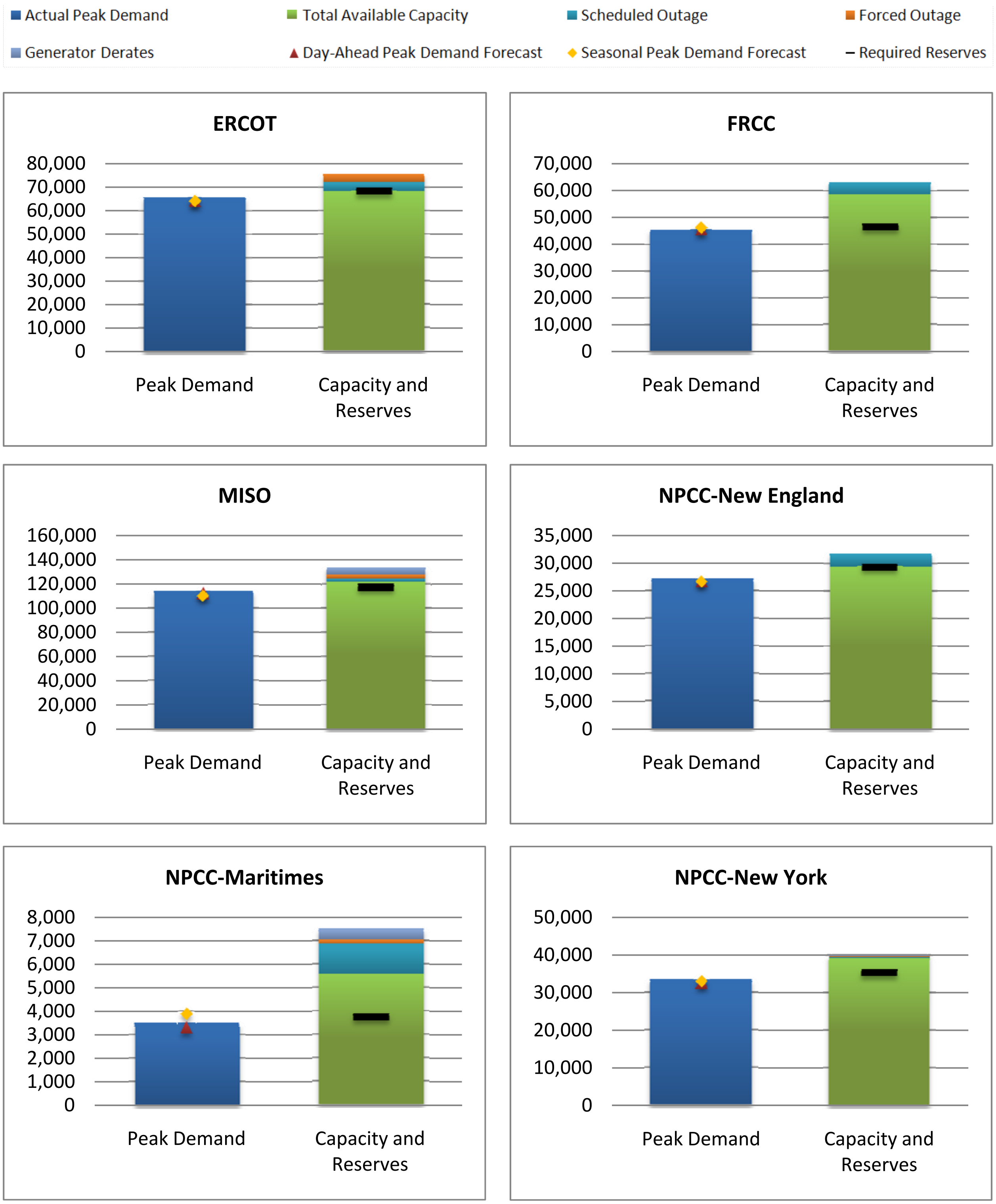
Area Self-Assessments

# Appendix I: Assessment Area Operating Reserves

*Note: Operating Reserve Margins are not comparable to Planning Reserve Margins. Operating Reserve Margins and requirements are generally based on real-time system conditions and may reflect the most-severe single contingency. Planning Reserve Margins are designed to measure longer-term resource adequacy and take primarily account for unexpected generator outages and demand forecast deviations.*

| Reliability Coordinator | Operating Reserve Margin (%) | Actual Reserves (MW) | Required Reserves (MW) | Requirement Met? |
|---|---|---|---|---|
| ERCOT | 15.2 | 2,650 | 2,300 | Yes |
| FRCC | 28.5 | 7,453 | 930 | Yes |
| NPCC-New England | 8.7 | 2,721 | 2,073 | Yes |
| NPCC-Maritimes | 1.0 | 1,373 | 260 | Yes |
| NPCC-New York | 17.4 | 5,832 | 1,800 | Yes |
| NPCC-Ontario | 21.0 | 5,254 | 1,453 | Yes |
| NPCC-Québec | 39.7 | 3,590 | 1,794 | Yes |
| MISO | 6.7 | 7,623 | 2,482 | Yes |
| PJM | 16.3 | 11,502 | 8,523 | Yes |
| SaskPower | 18.5 | 321 | 281 | Yes |
| SERC-Central | 17.3 | 2,794 | - | - |
| SERC-Delta | 37.1 | 1,543 | - | - |
| SERC-Gateway | 13.2 | 8,372 | - | - |
| SERC-Southeastern | 26.8 | 4,603 | - | - |
| SERC-VACAR | 17.0 | 2,410 | - | - |
| SPP | 37.9 | 2,161 | 1,187 | Yes |
| WECC-TOTAL | 14.7 | 21,039 | 10,177 | Yes |
| WECC-CA-MX | 8.0 | 4,399 | 3,798 | Yes |
| WECC-NWPP RSG | 22.2 | 11,731 | 3,804 | Yes |
| WECC-RMRG | 15.7 | 1,608 | 653 | Yes |
| WECC-SRSG | 13.0 | 3,301 | 1,922 | Yes |

# Appendix II: Assessment Area On-Peak Resource Adequacy




Appendix II: Assessment Area On-Peak Resource Adequacy

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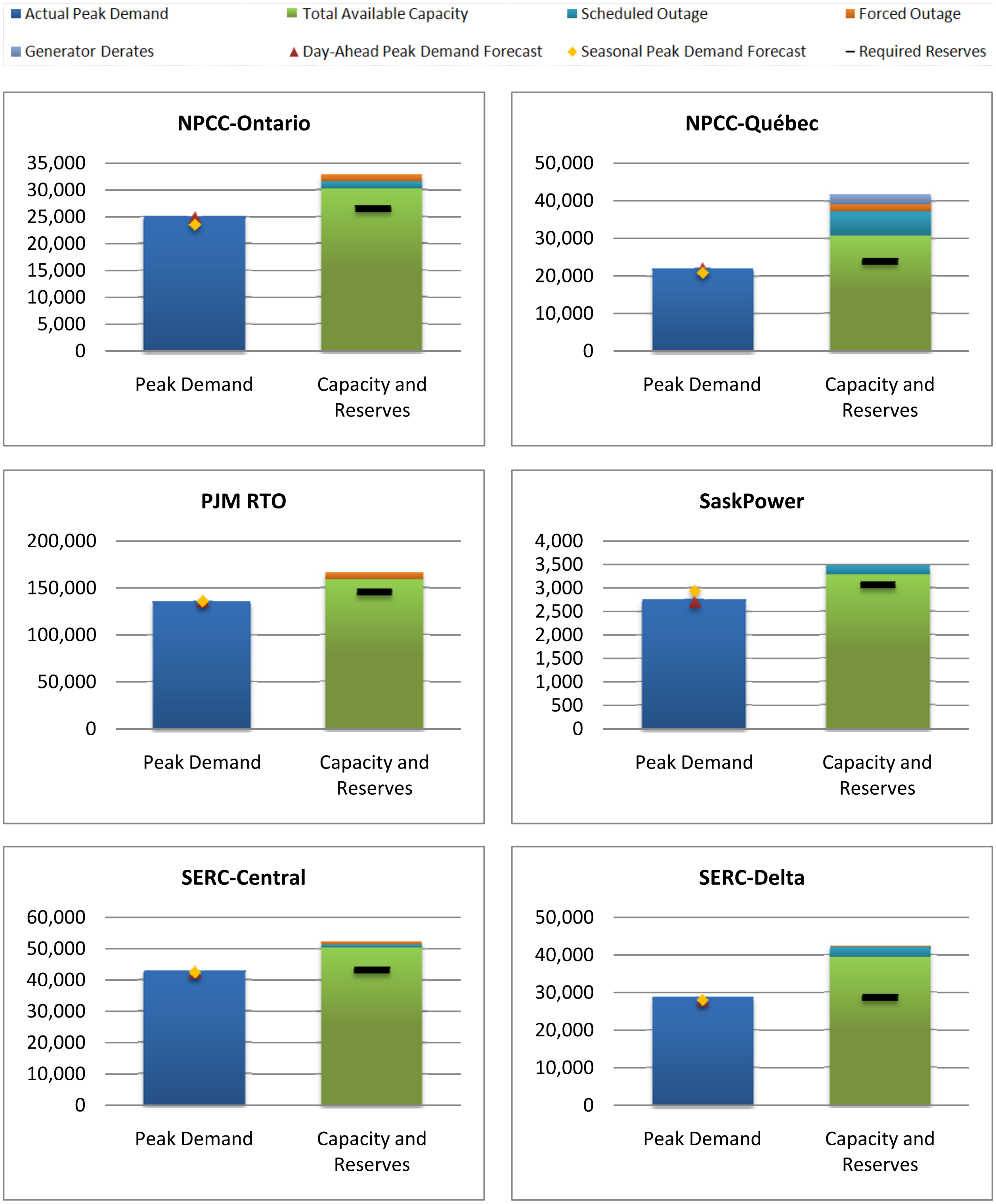



Actual Peak Demand
Total Available Capacity
Scheduled Outage
Forced Outage
Generator Derates
Day-Ahead Peak Demand Forecast
Seasonal Peak Demand Forecast
Required Reserves
SERC-Gateway
25,000
20,000
15,000
10,000
5,000
0
Peak Demand
Capacity and Reserves
SERC-Southeastern
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Peak Demand
Capacity and Reserves
SERC-VACAR
60,000
50,000
40,000
30,000
20,000
10,000
0
Peak Demand
Capacity and Reserves
SPP
100,000
80,000
60,000
40,000
20,000
0
Peak Demand
Capacity and Reserves
WECC-TOTAL
200,000
150,000
100,000
50,000
0
Peak Demand
Capacity and Reserves
WECC-CAMX
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Peak Demand
Capacity and Reserves

Appendix II: Assessment Area On-Peak Resource Adequacy

# Appendix III: Major Regional Disturbances & Unusual Occurrences (U.S. Only)

| Major Disturbances & Unusual Occurrences, June – September 2010 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Area | Date | Utility | Time | Area Affected | Type of Disturbance | Loss (MW) | Customers Affected[53] | Restoration |
| **June** | | | | | | | | |
| RFC | 6/1/2010 | Southern Indiana Gas and Electric Company | 10:03 p.m. | Southwestern Indiana | Firm Load Shed | 500 | 1 | 12:30 a.m. June 18 |
| TRE | 6/2/2010 | CPS Energy | 8:18 p.m. | San Antonio, TX | Severe Weather | N/A | 126,000 | 8:00 a.m. June 04 |
| WECC | 6/6/2010 | Pacific Gas and Electric | 4:45 a.m. | Northern California | Electric System Separation | 3 | 2,650 | 5:35 a.m. June 06 |
| WECC | 6/7/2010 | Public Service Company of Colorado | 6:29 p.m. | Denver Metropolitan Area | Firm Load Shed | 300 | 31,000 | 1:00 a.m. June 08 |
| TRE | 6/8/2010 | Centerpoint Energy | 11:00 a.m. | Southeastern Texas | Thunderstorms | N/A | 79,741 | 5:00 p.m. June 08 |
| SERC | 6/9/2010 | North Carolina Eastern Municipal Power Agency | 2:18 p.m. | Edenton, NC | Transmission System Interruption | N/A | 4,196 | 3:00 p.m. June 09 |
| NPCC | 6/16/2010 | Orange and Rockland Utilities | 11:11 a.m. | New York (Rockland and Orange Counties) | Voltage Reduction (System Test) | N/A | N/A | 11:32 a.m. June 16 |
| SPP | 6/17/2010 | Louisiana Energy and Power Authority | 8:30 a.m. | Morgan City, LA | Made Public Appeal | N/A | N/A | 5:47 p.m. June 17 |
| SERC | 6/17/2010 | Entergy | 9:30 a.m. | Southern Louisiana | Made Public Appeal | N/A | N/A | 5:17 p.m. June 17 |
| SERC | 6/17/2010 | Cleco Power LLC | 9:30 a.m. | Southern Louisiana | Made Public Appeal | N/A | N/A | 4:40 p.m. June 17 |
| SPP | 6/17/2010 | Southwest Louisiana Electric Membership Corporation | 9:30 a.m. | Southwestern Louisiana | Made Public Appeal | N/A | N/A | 4:40 p.m. June 17 |
| MRO | 6/17/2010 | Western Area Power Administration | 10:49 a.m. | Eastern Montana | Electrical System Separation | N/A | N/A | 11:02 a.m. June 17 |
| RFC | 6/18/2010 | Northern Indiana Public Service Company | 3:30 p.m. | Northwest Indiana | Thunderstorms | N/A | 94,345 | 12:30 a.m. June 20 |
| RFC | 6/18/2010 | Commonwealth Edison (RFC) | 4:00 p.m. | Chicago, IL | Severe Weather | N/A | 400,000 | 1:00 p.m. June 20 |
| RFC | 6/18/2010 | Consumers Energy | 7:00 p.m. | Southern Portion of Lower Michigan | Thunderstorms | N/A | 100,000 | 5:00 a.m. June 19 |
| RFC | 6/18/2010 | American Electric Power | 8:00 p.m. | Indiana, Michigan | Severe Weather | N/A | 79,000 | 10:45 a.m. June 21 |
| RFC | 6/18/2010 | Detroit Edison | 8:00 p.m. | Detroit, MI | Severe Weather | N/A | 150,000 | 7:30 p.m. June 22 |
| RFC | 6/21/2010 | Duke Energy Midwest | 1:48 p.m. | Cincinnati, OH | Thunderstorms | 400 | 50,636 | 8:31 p.m. June 22 |
| SERC | 6/22/2010 | Entergy | 3:34 p.m. | West/Central Arkansas | Made Public Appeal/Transmission Equipment Failure | 84 | 25,159 | 7:00 p.m. June 22 |

[53] Estimated Values based on Form OE-417 (http://www.oe.netl.doe.gov/OE417_annual_summary.aspx).



Appendix III: Major Regional Disturbances & Unusual Occurrences

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| RFC | 6/23/2010 | Commonwealth Edison | 5:00 p.m. | Chicago, IL | Severe Weather | N/A | 300,000 | 1:40 p.m. June 25 |
| RFC | 6/23/2010 | Northern Indiana Public Service Company | 5:48 p.m. | Northwest Indiana | Thunderstorms | N/A | 53,000 | 2:21 a.m. June 24 |
| RFC | 6/24/2010 | Atlantic City Electric | 3:00 p.m. | Southwestern New Jersey | Thunderstorms | N/A | 150,000 | 12:00 p.m. June 29 |
| RFC | 6/24/2010 | PECO | 3:30 p.m. | Southeastern Pennsylvania | Thunderstorms | N/A | 355,000 | 11:59 p.m. June 29 |
| WECC | 6/25/2010 | Pacific Gas and Electric | 11:36 p.m. | Northern California | Electrical System Separation | N/A | N/A | 1:38 a.m. June 26 |
| **July** | | | | | | | | |
| RFC | 7/6/2010 | Delmarva Power & Light Company | 3:47 a.m. | Newark, DE | Transformer Outage | 95 | 18,400 | 4:37 a.m. July 06 |
| RFC | 7/7/2010 | PJM Interconnection, LLC | 4:13 p.m. | York, South Central Pennsylvania | Loss of Transmission Equipment | N/A | 43,903 | 10:29 p.m. July 07 |
| RFC | 7/15/2010 | Detroit Edison | 7:00 p.m. | Southeastern Michigan | Severe Weather | 540 | 127,534 | 11:30 p.m. July 19 |
| MRO | 7/17/2010 | Xcel Energy | 8:30 p.m. | Minnesota | Strong Winds, Tornadoes | N/A | 63,000 | 10:00 p.m. July 19 |
| NPCC | 7/21/2010 | ISO New England | 6:44 p.m. | Connecticut | Thunderstorms | N/A | 50,100 | 8:00 p.m. July 21 |
| WECC | 7/23/2010 | Pacificorp | 10:00 a.m. | Northern Utah | Made Public Appeals | N/A | N/A | 11:55 p.m. July 24 |
| RFC | 7/23/2010 | Detroit Edison | 7:30 p.m. | Southeastern Michigan | Severe Weather | 400 | 82,000 | 6:30 p.m. July 26 |
| RFC | 7/25/2010 | Potomac Electric Power Co | 3:10 p.m. | Washington, DC Region | Severe Weather | N/A | 297,700 | 11:30 p.m. July 30 |
| RFC | 7/25/2010 | Baltimore Gas and Electric | 3:20 p.m. | Central Maryland | Severe Weather | 480 | 124,000 | 6:00 p.m. July 27 |
| SERC | 7/25/2010 | Dominion - Virginia Power | 4:11 p.m. | Northern Virginia | Severe Weather | 900-1000 | 81,000 | 8:06 p.m. July 25 |
| SERC | 7/29/2010 | Dominion - Virginia Power | 5:43 p.m. | Virginia | Thunderstorms | N/A | 55,000 | 8:07 p.m. July 29 |
| WECC | 7/29/2010 | Southern California Edison Company | 6:39 p.m. | Southern California | Shed Interruptible Load, Wildfire | 522 | N/A | 7:26 p.m. July 29 |
| WECC | 7/29/2010 | California Independent System Operator | 6:39 p.m. | Southern California | Shed Interruptible Load, Wildfire | 522 | N/A | 7:26 p.m. July 29 |
| **August** | | | | | | | | |
| WECC | 8/2/2010 | California Department of Waters Resources | 12:00 p.m. | Central California | Fuel Supply Deficiency (Hydro) | N/A | N/A | 11:00 p.m. August 02 |
| SERC | 8/2/2010 | Cleco Power LLC | 12:45 p.m. | Southern Louisiana | Made Public Appeals | N/A | N/A | 11:00 a.m. August 04 |
| SERC | 8/2/2010 | Entergy | 12:45 p.m. | Southern Louisiana | Made Public Appeals | N/A | N/A | 11:00 a.m. August 04 |
| SERC | 8/2/2010 | Southwest Louisiana Electric Membership Corporation | 12:45 p.m. | Southwestern Louisiana | Made Public Appeals | N/A | N/A | 11:00 a.m. August 04 |
| SPP | 8/2/2010 | Lafayette Utilities Systems | 12:45 p.m. | Southern Louisiana | Made Public Appeals | N/A | N/A | 11:00 a.m. August 04 |
| SPP | 8/4/2010 | Southwestern Public Service Company | 12:00 p.m. | Northern Texas, Eastern New Mexico | Made Public Appeals | N/A | N/A | 10:00 p.m. August 04 |
| RFC | 8/4/2010 | Allegheny Power | 4:45 p.m. | Western Pennsylvania , Northwestern and Central West Virginia | Thunderstorms | 60 | 11,186 | 12:00 a.m. August 07 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| RFC | 8/4/2010 | American Electric Power | 5:00 p.m. | Ohio, West Virginia, Kentucky | Severe Weather | N/A | 37,000 | 4:00 a.m. August 06 |
| RFC | 8/5/2010 | Potomac Electric Power Co | 3:30 p.m. | District of Columbia, Maryland | Thunderstorms | N/A | 76,729 | 10:00 p.m. August 05 |
| RFC | 8/5/2010 | Dominion - Virginia Power | 3:54 p.m. | Northern Virginia | Thunderstorms | N/A | 145,157 | 12:00 a.m. August 08 |
| RFC | 8/9/2010 | AES Greenidge and Cayuga | 12:00 p.m. | Upstate New York | Fuel Supply Defiency | N/A | N/A | 12:00 p.m. August 16 |
| RFC | 8/11/2010 | American Electric Power | 3:21 p.m. | Ohio | Severe Weather | N/A | 57,000 | 12:12 p.m. August 11 |
| RFC | 8/12/2010 | Potomac Electric Power Co. | 6:45 a.m. | District of Columbia, Maryland | Severe Weather | N/A | 101,003 | 9:00 p.m. August 12 |
| SPP | 8/12/2010 | Nebraska Public Power District | 8:21 a.m. | Central Nebraska | Made Public Appeals | 65 | N/A | 11:00 a.m. August 12 |
| MRO | 8/12/2010 | Wisconsin Public Service | 3:42 p.m. | City of Oshkosh, Wisconsin | Made Public Appeals | 30 | 7,600 | 10:10 p.m. August 12 |
| RFC | 8/19/2010 | Detroit Edison | 6:00 p.m. | Southeastern Michigan | Severe Weather | 340 | 80,000 | 3:30 p.m. August 23 |
| TRE | 8/23/2010 | CenterPoint Energy | 5:50 p.m. | Houston, Texas | Severe Weather | 746 | 81,586 | 9:30 a.m. August 24 |
| **September** | | | | | | | | |
| WECC | 9/1/2010 | Pacific Gas and Electric | 10:20 a.m. | Pittsburg (Bay Area), California | Electrical System Separation (Islanding) | 31 | 15,000 | 12:44 p.m. September 01 |
| TRE | 9/7/2010 | CPS Energy | 2:02 p.m. | San Antonio, Texas | Tropical Storm | N/A | 340,350 | 1:27 a.m. September 08 |
| SERC | 9/20/2010 | Birchwood Power Facility | 5:00 p.m. | King George County, Virginia | Low Flying Helicopter | N/A | N/A | 5:30 p.m. September 20 |
| RFC | 9/21/2010 | Consumers Energy | 9:31 p.m. | Central and Southern Michigan | Thunderstorms | N/A | 138,000 | 2:30 p.m. September 22 |
| WECC | 9/22/2010 | California Department of Water Resources | 6:12 a.m. | Bakersfield, California | Firm Load Shed | 526 | N/A | 11:00 p.m. September 22 |
| RFC | 9/22/2010 | Duquesne Light Company | 4:08 p.m. | City of Pittsburgh, Pennsylvania | Thunderstorms | 156 | 52,000 | 12:00 a.m. September 26 |
| RFC | 9/22/2010 | Allegheny Power | 5:38 p.m. | Western Pennsylvania | Thunderstorms | 389 | 82,861 | 11:30 p.m. September 24 |
| WECC | 9/27/2010 | Southern California Edison Company | 3:15 p.m. | Central and Southern California | Interruptible Load Shed | 595 | N/A | 6:12 p.m. September 27 |

# Appendix IV: Additional Information

### MISO Wind

The MISO posts hourly aggregate wind generation output on their web site. This includes the wind generation output for the MISO market footprint only (7567 MW nameplate, or 92 percent of the full MRO region). MRO staff has calculated an actual capacity factor of 24.5 percent for the four month summer period (2928 hours). This can be compared to the 40 percent annual average capacity factor for the region. There were 123 hours during the summer months where the demand was at 95 percent or more of forecast peak load. The actual capacity factor for these "on-peak" hours was 17.5 percent. This can be compared to the eight percent that is used in the summer assessment that is expected to be available at any given hour. It should be noted that this data is for one season only and does not include any forced or planned outages of individual wind turbines (which would increase the actual capacity factors).

Several of the peak days in August 2010 occurred on August 9, 11, and 12, 2010. The wind power output in the MISO, Western Area Power Administration (WAPA), and Manitoba Hydro (MHEB) Balancing Areas for those days are shown below. The installed nameplate capacity was 7567 MW for the MISO BA, 558 MW for WAPA BA, and 99.9 MW for MHEB BA. Manual wind curtailments for these days for the MISO were as high as 5 MW on August 9, 40 MW on August 11, and 328 MW on August 12. WAPA or MHEB did not have any curtailments during these times.

**FIGURE IV.1: WIND OUTPUT DURING PEAK ON AUGUST 9, 2010**

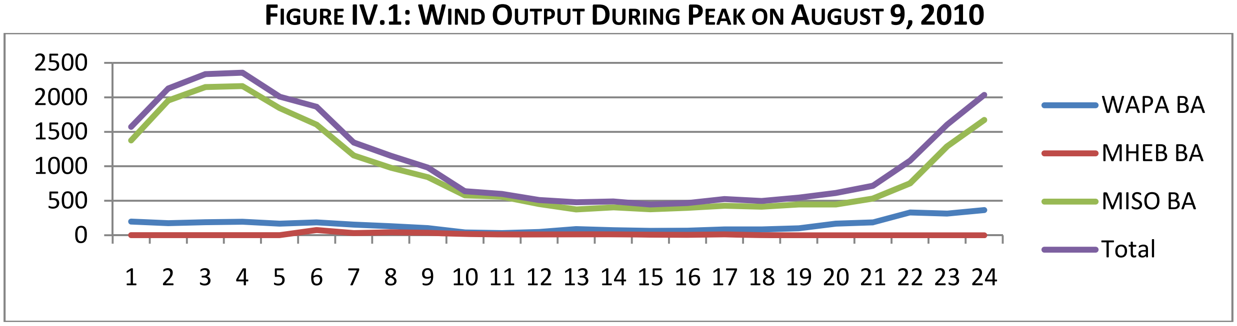



**FIGURE IV.1: WIND OUTPUT DURING PEAK ON AUGUST 11, 2010**

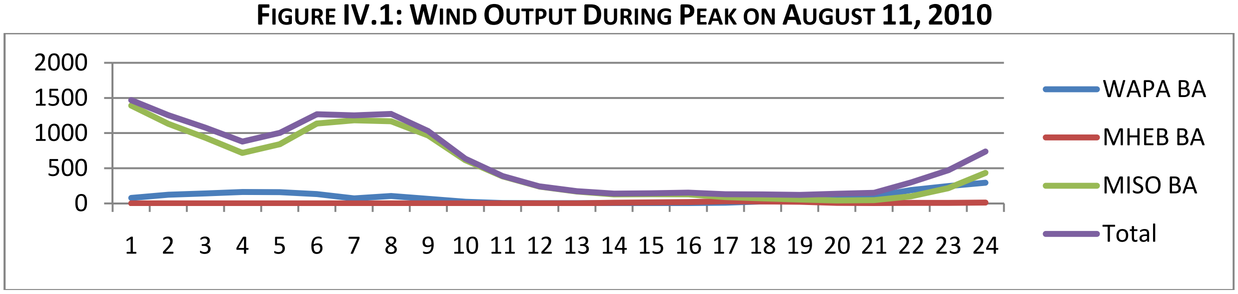
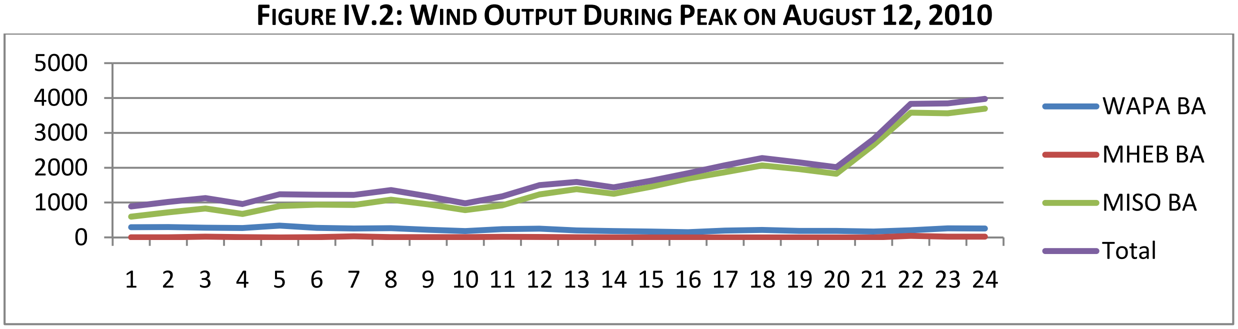



**FIGURE IV.2: WIND OUTPUT DURING PEAK ON AUGUST 12, 2010**



# About This Report

The *2010 Post-Summer Reliability Assessment* represents NERC's independent judgment of the performance of the bulk power system in North American for the previous 2010 summer season (Table B).[54] The report specifically provides a high-level reliability assessment of 2010 summer resource adequacy and operating reliability, an overview of significant events, Regional highlights, and Regional self-assessments.

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

**Table B: NERC's Annual Assessments**

| Assessment | Outlook | Publish Target |
|---|---|---|
| Summer | Upcoming season | May |
| Post-Summer | Previous season | November |
| Long-Term Assessment | 10 year | October |
| Winter | Upcoming season | November |
| Post-Winter | Previous season | May |

## Report Preparation

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

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

[54] 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 Summer Reliability Assessment,*** May 26, 2010
http://www.nerc.com/files/2010%20Summer%20Reliability%20Assessment.pdf

***Glossary of Terms Used in Reliability Standards***, Updated April 20, 2010
http://www.nerc.com/docs/standards/rs/Glossary_of_Terms_2010April20.pdf

***Reliability Assessments Guidebook***, Version 2.1, September 23, 2010
http://www.nerc.com/files/Reliability%20Assessment%20Guidebook%20v2.1.pdf

***Reliability Standards for the Bulk Electric Systems in North America*****,** Updated May 20, 2009
http://www.nerc.com/files/Reliability_Standards_Complete_Set_2009May20.pdf

# Reliability Assessment Subcommittee Roster

| | | | |
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| | | | |
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| | | | |
|---|---|---|---|
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| | | | |
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