NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

June 4, 2009

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: North American Electric Reliability Corporation, *2009 Summer Reliability Assessment*, Docket No. RC09-_-000

Dear Secretary Bose:

The North American Electric Reliability Corporation (NERC) submits solely as an informational filing the 2009 Summer Reliability Assessment that was prepared by NERC and released on May 19, 2009. NERC is not requesting the Federal Energy Regulatory Commission to take any action on this assessment.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins

Holly A. Hawkins

Attorney for North American Electric Reliability Corporation

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2009 Summer Reliability Assessment

to ensure the reliability of the bulk power system

May 2009

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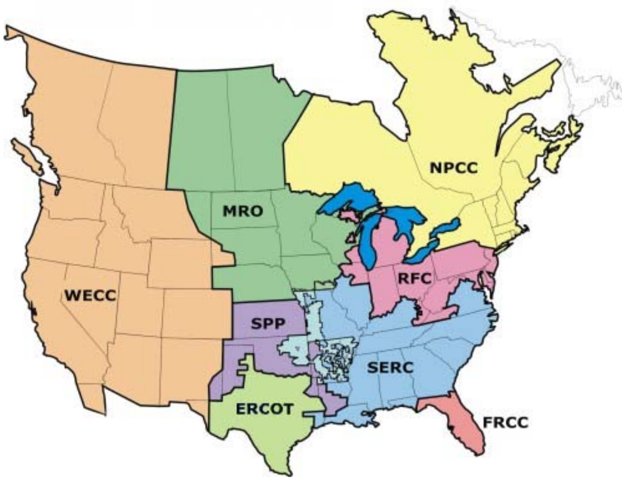
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy 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 a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports[2] 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).[3] 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

ERCOT Electric Reliability Council of Texas	**RFC** Reliability*First* Corporation
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council, Inc.	**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 bulk power system, and made compliance with those standards mandatory and enforceable. Reliability Standards are also mandatory and enforceable in Ontario and New Brunswick, and NERC is seeking to achieve comparable results in the other Canadian provinces. NERC will seek recognition in Mexico once necessary legislation is adopted.

[2] Readers may refer to the *Reliability Concepts Used in this Report* Section for more information on NERC's reporting definitions and methods.

[3] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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Key Findings

1. Recession Drives Broad Decline in Forecast Demand; Reserve Margins Increase

Figure 1a: NERC Forecast Summer Peak-Demand, 2001 to 2009

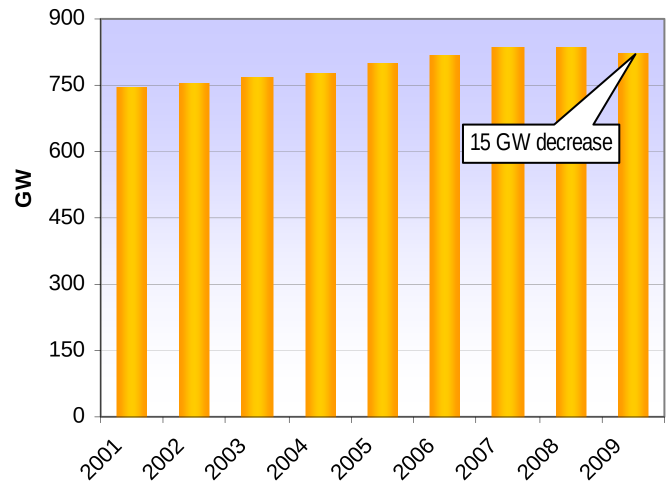
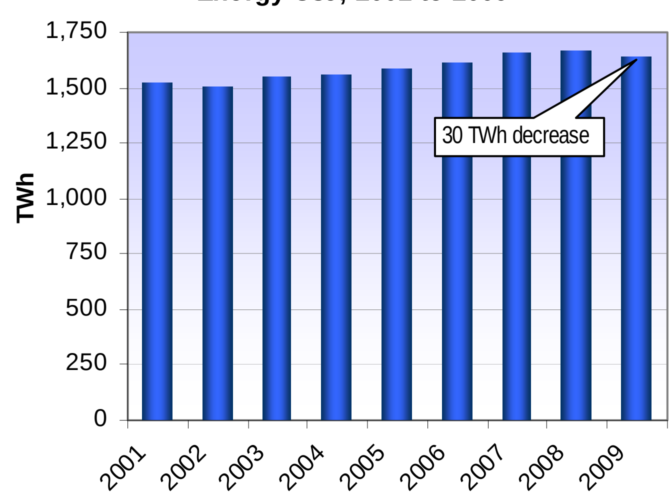


Figure 1b: NERC Forecast Summer Energy Use, 2001 to 2009



Decreased economic activity across North America is primarily responsible for a significant drop in peak-demand forecasts for the 2009 summer season (Figure 1). Compared to last year's demand forecast, a North American-wide reduction of nearly 15 GW (1.8 percent) is projected. In addition, summer energy use is projected to decline by over 30 Terawatt hours (TWh), trending towards 2006 summer levels. While year-over-year reduction in electricity use is not uncommon — industrial use of electricity has declined in 10 of the past 60 years[4], for example — it is critical that infrastructure development continues despite this decline. Based on the information provided as part of this assessment, most Regions have not yet experienced adverse impacts on infrastructure projects. However, WECC has indicated that some generation and transmission projects have been deferred or cancelled, in part due to overall economic factors.

All Regions are expected to have sufficient reserve margins to ensure reliability throughout the 2009 summer months. Summer peak reserve margins[5] across North America are expected to be 4.7 percentage points higher in 2009 than in 2008 due to the reduction in demand forecasts and a 2.3 percent increase in new resources. In the U.S., reserve

[4] http://www.eia.doe.gov/emeu/aer/elect.html

[5] The *2008 Summer Reliability Assessment* and prior reliability assessments used capacity margin, which has been replaced by the reserve margin in the *2009 Summer Reliability Assessment*. Accordingly, these margins cannot be directly compared without recalculation. Reserve margins measure the amount of installed resources over and above peak demand that are available to provide for planned and unplanned outages of generating capacity, load forecast deviations, and operating reserves. For further explanation and Capacity Margin comparisons, refer to the *Capacity Margin to Reserve Margin Changes* Section and Table 5a through 5d of this report.

margins are projected to remain above 25 percent (Figure 2a) throughout the summer months — well above the 15 percent NERC Reference Reserve Margin level.[6] Reserve margins are even higher in much of Canada (Figure 2b), as demand there typically peaks during the winter

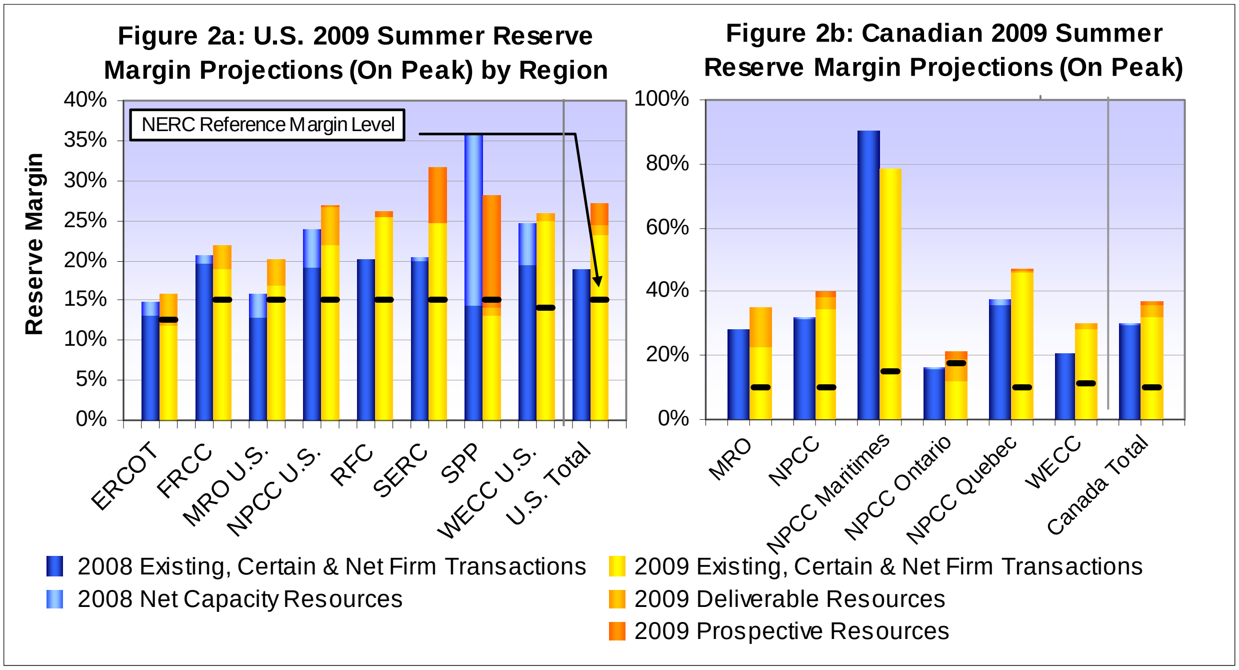


Figure 2a: U.S. 2009 Summer Reserve Margin Projections (On Peak) by Region

Figure 2b: Canadian 2009 Summer Reserve Margin Projections (On Peak)

months. Reserve margins in U.S. subregions in NPCC, SERC[7] and WECC are also projected to be above the 15 percent NERC Reference Reserve Margin level (Figure 3).

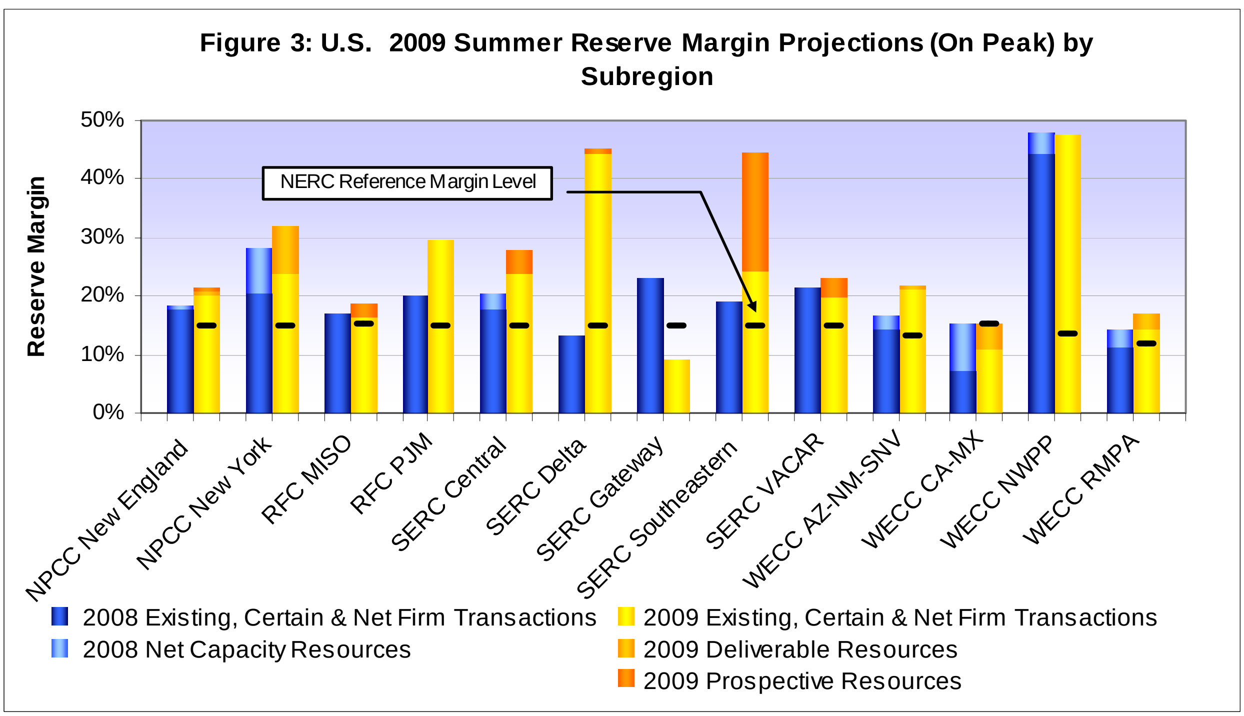


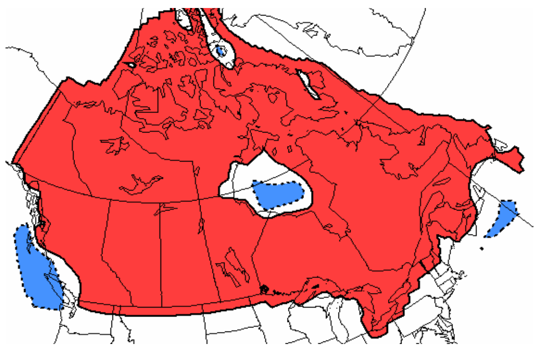
Figure 3: U.S. 2009 Summer Reserve Margin Projections (On Peak) by Subregion

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

[7] The Gateway subregion of SERC anticipates reporting additional Existing-Certain capacity in May 2009, when the Illinois Power Agency is expected to complete the procurement of capacity resources for the Ameren Illinois Utilities pursuant to Illinois Commerce Commission rules for the 2009 summer and beyond. SERC's self-assessment summarizes this process and identifies 23,439 MW of existing generation in the Gateway subregion.

Weather and temperature are key drivers for peak electricity demand in North America. In most of the U.S., summer temperatures are projected to be normal (See Figure 4b).[8] Much of the Western Interconnection, however, is projected to experience warmer than average weather patterns. Many areas of Canada are forecast to experience normal or above normal temperatures for the 2009 summer (See Figure 4a).[9] These temperature variations are not expected to affect reliability during the 2009 summer season.

Figure 4a: Canadian Summer Mean Temperature Anomaly Outlook, June to August 2009



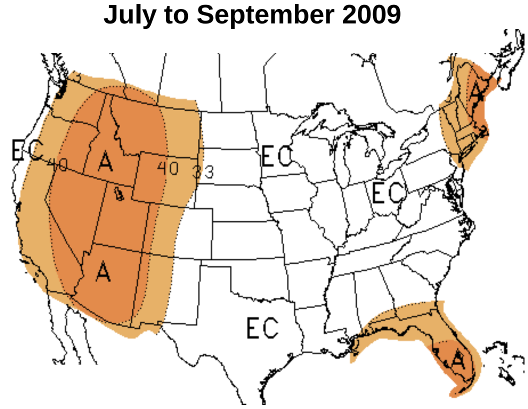
Source: Environment Canada, 5/1/09

Red – **Above normal temperatures forecast when compared to the 30 seasons of the 1971-2000 period.**

White – **Normal temperatures forecast when compared to the 30 seasons of the 1971-2000 period.**

Blue – **Below normal temperatures forecast when compared to the 30 seasons of the1971-2000 period.**

Figure 4b: U.S. Summer Mean Temperature Probability Outlook, July to September 2009



Source: Climate Prediction Center at NOAA, 4/16/09

A (40) – 40% to 49% chance of temperatures being significantly above normal*

A (33) – 34% to 39% chance of significantly above normal temperatures*.

EC – There is no significant shift in the expected range of temperatures this year in relationship to the 1971-2000 period.

[8] http://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=3
[9] For more information on Canadian temperature forecasts, including the statistical significance of the areas in Figure 4a above, see http://www.weatheroffice.gc.ca/saisons/index_e.html.

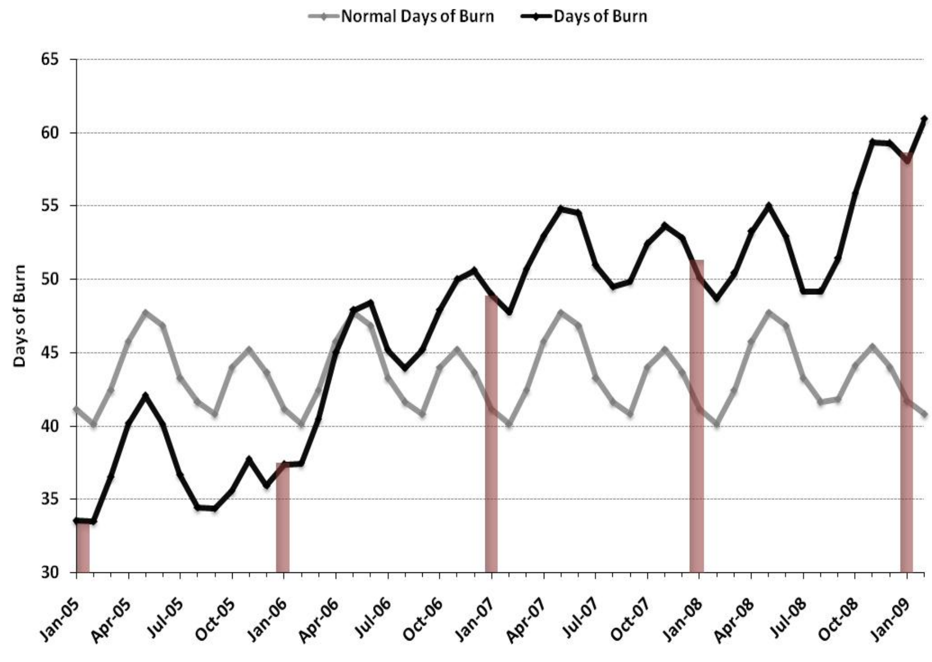
2. Coal and Natural Gas Fuel Forecasts Appear Adequate

Overall, U.S. fossil-fuel inventories, supply and delivery capability appear adequate to support generation resources needed to maintain reliability for the 2009 summer season. Coal stockpiles are currently at 49.2 percent above average and natural gas storage at 22.9 percent above average.

Coal

U.S. coal stockpiles are at high levels due to less expensive and more accessible coal resources (See Figure 5) than have been seen over the past several years. U.S. eastern regional coal inventories are approximately 52 days of normal burn [10], exceeding the five-year high, and inventories of Powder River Basin coal are roughly 69 days of normal burn. These stockpiles appear to be adequate to deal with any unexpected short-term fuel delivery disruptions.

Figure 5: Total U.S. Electric Generation Coal Stockpiles, 2005 to 2009



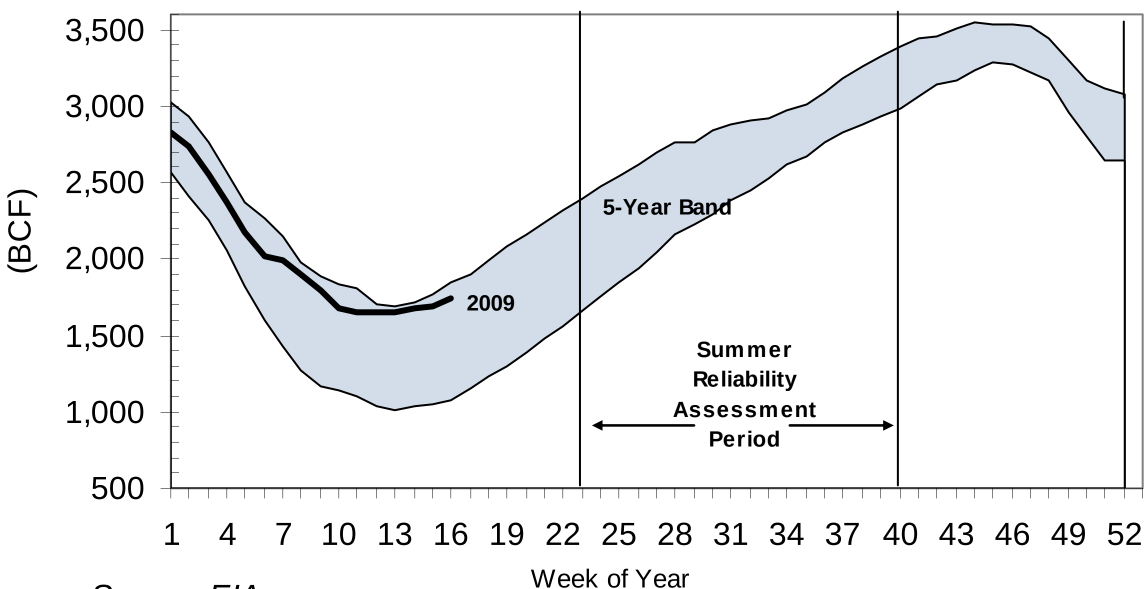
[10] "Normal burn" is based on a five-year average of coal consumed in coal-fired generation plants.

Natural Gas

The U.S. natural gas supply balance is ample to serve the electric industry during the 2009 summer. At the end of the 2008/2009 winter season, U.S. working gas [11] in storage was at about 1.65 BCF, compared to the 1.7 BCF historic maximum (Figure 6). [12] In early April, Canadian working gas in storage stood at 31 percent full versus 24 percent one year earlier. Summer storage injections could exceed available U.S. storage capacity, despite significant additions to storage capacity scheduled to come online. [13] Maximum capacity should be reached before November 1st, which marks the end of the traditional injection season.

Multiple years of rising U.S. natural gas production have outpaced demand, while consumption has declined sharply due to the global recession. Supplies exceeded demand by 5 billion cubic feet per day (BCFD) in late 2008, an oversupply condition that is expected to persist through 2009 with a surplus balance possible through 2010 and 2011.

Figure 6: 2009 U.S. Working Gas in Storage



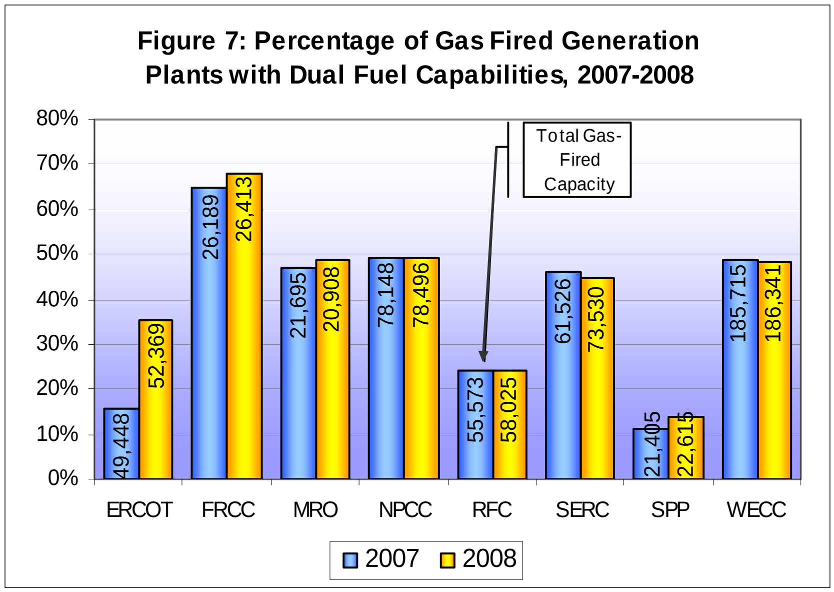
Source: EIA

[11] Working gas is the volume of gas in the reservoir above the level of base gas and is available to the marketplace.
[12] http://www.eia.doe.gov/oil_gas/natural_gas/ngs/ngs.html
[13] About 250 BCF of new U.S. working natural gas storage capacity is forecast to come online this summer.

A severe hurricane on the Gulf Coast of the U.S. presents the greatest potential risk for disrupting the U.S. natural gas balance. The increase in global liquefaction capacity[14], scheduled to grow by 30 percent in the second half of 2009, could mitigate the impacts of a hurricane. Higher U.S. gas prices due to disruptions from hurricanes could draw liquefied natural gas (LNG) cargoes from around the world. However, LNG can present additional challenges due to its diverse origins and compositions.[15] In cases where a number of combined-cycle gas-fired units with low NOx burners obtain their fuel from the same pipelines, changes in gas heat content can result in multiple unit trips at nearly the same time, which may affect bulk power system operating reliability.

Fuel Delivery Contingencies and Fuel Industry Coordination

No Regions anticipate reliability concerns related to fuel supply or fuel delivery for the summer of 2009. Regions/subregions currently rely upon industry participants to provide information on the adequacy of fuel supply and delivery conditions and currently do not require verification of the operability of the backup fuel systems or inventories. Many Regions have substantial dual fuel[16] capabilities (Figure 7) to support contingencies and for economic considerations.



Regions/subregions that are heavily dependent upon a single fuel type have additional operational and coordination measures in place. For instance, FRCC coordinates the activities between natural gas suppliers and generators within its Region, and ISO-NE continuously monitors the regional natural gas pipeline systems. Similarly, MRO and its members closely monitor the delivery of Powder River Basin coal to ensure adequate supply.

[14] New liquefaction projects likely to come online in 2009 and 2010 include Qatargas II Train 4 & 5 (each 1,067 MMCFD), RasGas III Train 6 (1,067 MMCFD), Yemen LNG Bal Haf Trains 1 & 2 (894 MMCFD), Sakhalin Island II Train 1 (640 MMCFD), and Pampa Melchorita (594 MMCFD), among others.

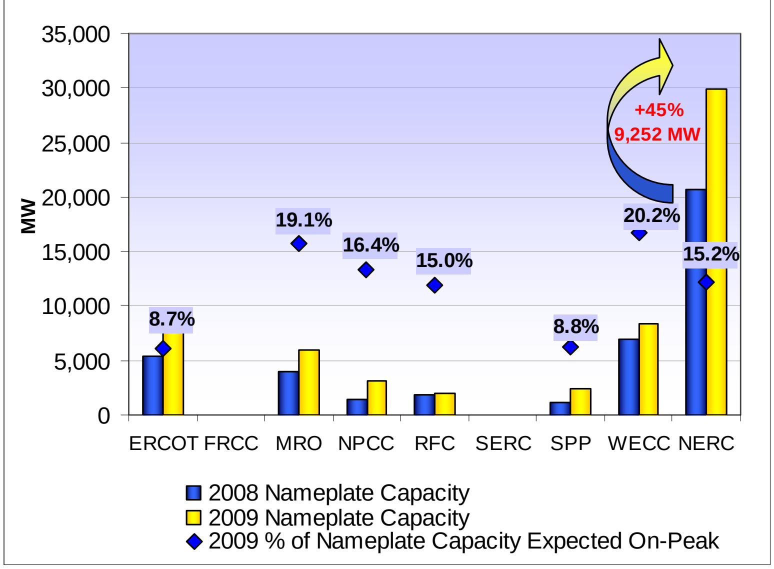
[15] Combined-cycle gas-fired units with low NOx burners can be sensitive to unanticipated, transient changes in natural gas heat content (+/- 5% Btu/cu-ft) potentially triggering automatic control-action to avoid flameout and equipment damage.

[16] Dual fuel capability refers to units that can use multiple fuel sources. In North America, the predominant fuels used for this purpose are gas or oil.

3. Nameplate Wind Capacity Grows by More Than 9,000 MW

Projected summer installed nameplate[17] wind capacity increased by 9,252 MW, or 44.7 percent, from 2008 to 2009, to 29,945 MW (Figure 8).[18] All regions with wind resources reported an increase in nameplate capacity, with NPCC doubling its wind resources.

Figure 8: Wind Resources Summer 2008 and 2009



On-peak capacity from wind plants, as a percentage of "nameplate capacity," ranges from zero to over 20 percent for NERC Regions during the 2009 summer. The expected average on-peak capacity for the 2009 summer is forecast to be 15.2 percent of nameplate capacity, representing an on-peak increase from 3,739 MW to 4,544 MW, or 21.5 percent, from the 2008 summer season (Table 1).

On-peak capacity values shown by Region in Figure 8 are a consolidated calculation of sub-regional values, which may vary widely. For example, NPCC subregions use diverse policies and methods to calculate expected on-peak capacity of wind generation, with results ranging from zero to 50 percent of nameplate capacity (see Table 1). When averaged across the region, these numbers result in an expected 16.4 percent on-peak value for wind resources. Consistent, agreed-upon methods to determine on-peak wind capacity are needed to ensure uniform measurement of its contribution to reserve margins.[19] Three approaches are currently in use: 1) Effective Load Carrying Capability, 2) historical performance, and 3) deploying a flat percentage. NERC, through its Integration of Variable Generation Task Force, is working with industry to address these issues by 2010.

[17] From EIA: Installed nameplate capacity [Generator nameplate capacity (installed)]: "The maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator." http://www.eia.doe.gov/glossary/glossary_i.htm Therefore installed nameplate capacity equals "Wind Expected On-Peak" (line 6a1) plus "Wind Derate On-Peak" (line 6b1) as reported to NERC for this assessment.

[18] NERC's nameplate wind capacity increase compares favorably with reports by the American Wind Energy Association (AWEA) and Canada Wind Energy Association (CanWEA). AWEA reported on 1/27/09 an increase of 8,358 MW of installed wind nameplate capacity in the U.S. 2008 based on a survey of its members. (http://www.awea.org/newsroom/releases/wind_energy_growth2008_27Jan09.html) CanWEA reported an increase of 523 MW of installed wind nameplate capacity in Canada in 2008. (http://www.canwea.ca/pdf/installed_capacity_april%2009_e.pdf)

[19] http://www.nerc.com/files/IVGTF_Report_041609.pdf

Reliability Considerations

Regions integrating wind resources have projected an increase in transmission congestion in the 2009 summer, particularly during low demand levels. As wind resources are less predictable and follow the availability of their fuel (wind) rather than demand, different patterns in the use of transmission capacity can emerge. Further, some Regions report challenges in managing the variability and magnitude of wind resources and the need to provide additional ancillary services (such as operating reserves) as specific challenges. Nevertheless, integration of the substantial projected increase of wind resources appears to be manageable for the 2009 summer.

Many Regions/subregions are actively studying wind integration considerations such as wind forecasting, interconnection standards, new operator tools, and protection/control systems. NERC will continue to monitor the operational challenges of wind integration to ensure the reliability of the bulk power system is maintained.

Table 1: 2009 Summer Wind Resources by NERC Region

Region	Nameplate Capacity (MW)	% of Nameplate Capacity Expected on Peak
ERCOT	8,065	8.7%
FRCC	0	NA
MRO	5,924	20.0%
NPCC	3,151	16.4%
NPCC-Maritimes	543	50.5%
NPCC-New England	100	39.0%
NPCC-New York	1,273	10.0%
NPCC-Ontario[20]	704	11 to 18%
NPCC-Quebec	531	0%
RFC[21]	2,000	13 to 20%
SERC	29	0.0%
SPP[22]	2,474	8.8%
WECC[23]	8,301	0 to 26.8%

[20] For the Ontario subregion of NPCC, the on-peak capacity contribution from wind for the summer months, June, July and August, is assumed 11 percent of the installed capacity. The wind capacity contribution for September is assumed 18 percent.

[21] PJM and MISO are two RTOs within RFC. In PJM, until three years of operating data is available for a specific wind project, a 13 percent capability is assigned for each missing year of data. In MISO, wind power providers may declare up to 20 percent of nameplate capability as a Capacity Resource.

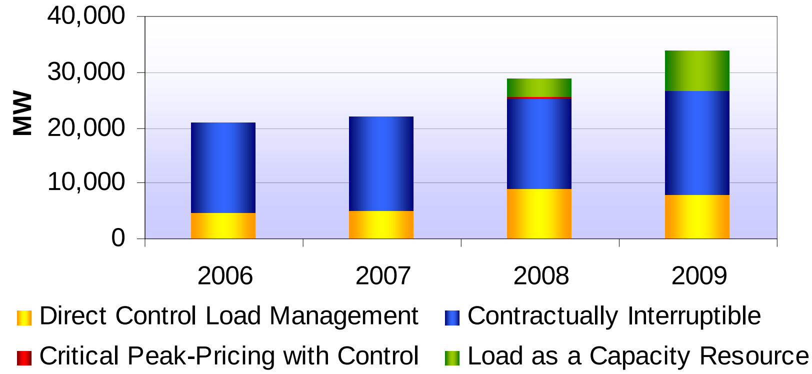
[22] Wind plants in SPP calculate a monthly "net capability" based on a minimum of the most recent five years of hourly net power output (MW) data. For the entire SPP region, this average is about 9 percent. For more details, please refer to section 12.1.5.3.g of the Southwest Power Pool Criteria of 1/27/2009 located at http://www.spp.org/publications/CurrentCriteria01272009-with%20Appendices.pdf.

[23] BAs within WECC determine expected on-peak wind capacity by using a variety of methods. Some examples of those methods are assume zero capacity from wind capacity towards meeting the on-peak demand, use 5 percent of the installed capacity as on-peak capacity, and use historical area-specific wind flow patterns to determine an expected on-peak capacity. The percentages of expected on-peak capacity to nameplate across WECC subregions are NWPP-18.7 percent, CAMX-26.8 percent, RMPA-12.1 percent, and AZ-NM-SNV-6.9 percent.

4. Demand Response Increasingly Contributes to Capacity

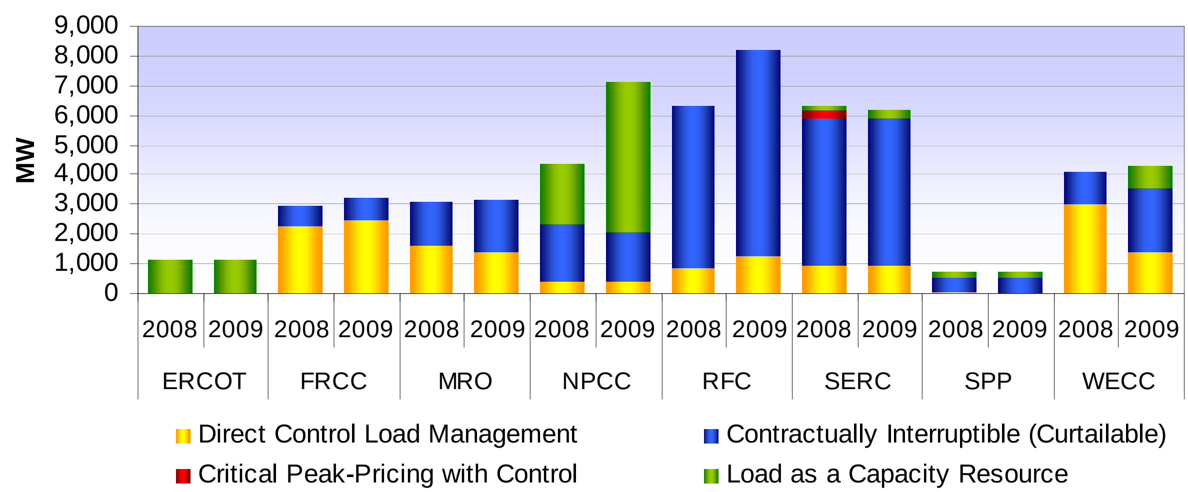
Demand response[24] used to reduce peak load for the 2009 summer is projected to increase by 8 percent (more than 2,200 MW) from the 2008 summer (Figure 9). NPCC and RFC forecast increases of 64 and 30 percent, respectively, and FRCC projects an increase of 9 percent. ERCOT, MRO, SERC, SPP, and WECC projections remain relatively flat.

Figure 9: NERC Summer Peak Demand Response Projections (2006-2009)



Projected demand response as a percentage of total summer peak demand across North America (Figure 10) is 4 percent for the 2009 summer. FRCC, MRO, and NPCC have the highest projected demand response at 6.4 to 7 percent. Projected on-peak demand response in ERCOT and SPP are less than half of the North American average at 1.7 percent each.

Figure 10: NERC Summer Peak Capacity Demand Response 2008-2009 Comparison

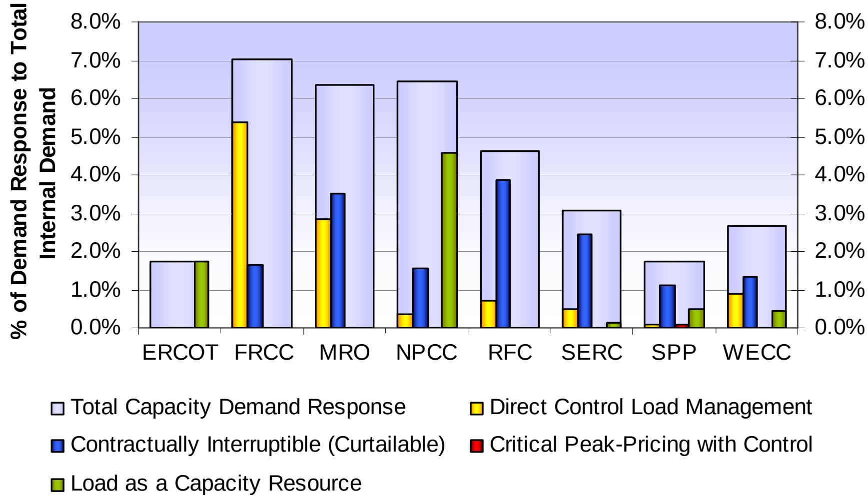


The greatest rise in demand response resources is seen in NPCC, where market mechanisms have encouraged significant development in demand response programs in ISO New England and New York ISO. As a result, the type of demand response program shown with the highest growth is "load acting as a capacity resource" (Figure 11).[25]

[24] Refer to the *Reliability Concepts Used in this Report* Section for a detailed explanation of demand response and Figure 17 for an overview of NERC's Demand-side management categories.

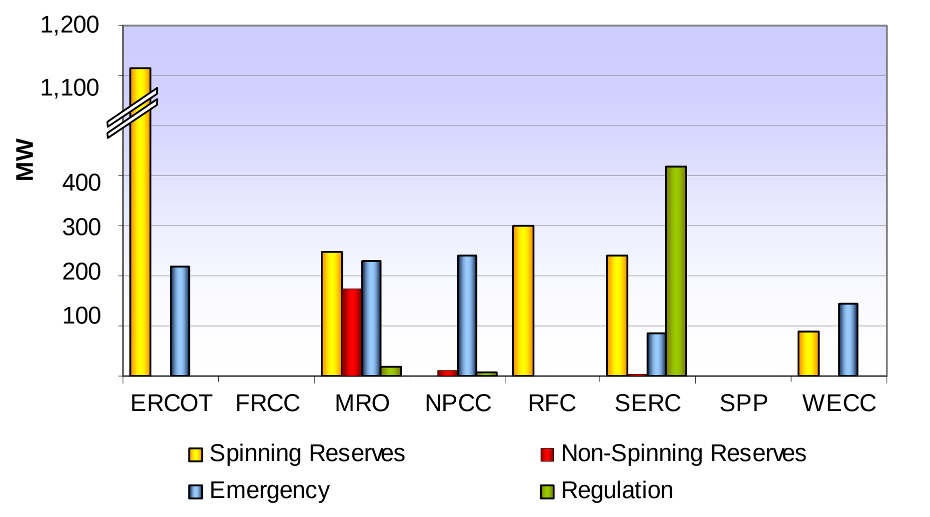
[25] See http://www.nerc.com/docs/pc/drdtf/NERC_DSMTF_Report_040308.pdf .

Figure 11: NERC Projected Demand Response as a % of 2009 Total Summer Peak Demand



NERC also collected projected demand response data used for ancillary services, defined as *demand-side resource displacing generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.*[26] In portions of the U.S., demand response used as ancillary services may increase during the 2009 summer season, due in part to the 2007 revision of FERC Order 890 pro-forma tariff.[27] Over 2,000 MW of ancillary and energy-voluntary services (non-capacity) are forecast for the 2009 summer (Figure 12).

Figure 12: Demand Response used for Ancillary Services and Energy-Voluntary - 2009 Summer Peak Projections



[26] See Glossary of ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/NERC_DSMTF_Report_040308.pdf for detailed definitions.
[27] http://ferc.gov/industries/electric/indus-act/oatt-reform.asp

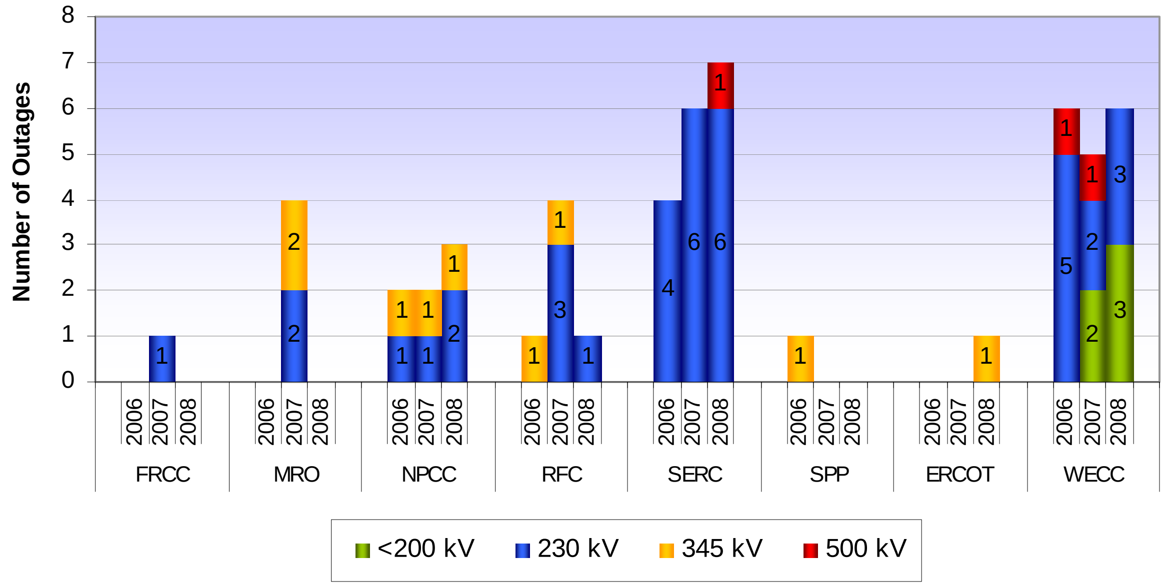
Historical Summer Reliability Trends

1. Vegetation Management

Figure 13 shows the total number of U.S. vegetation-related transmission outages (fall-ins and grow-ins) by Region and voltage class during the 2006-2008 summer seasons. In 2008, NPCC and SERC experienced an increase in vegetation-related outages in comparison to 2006 and 2007. WECC reported six outages in 2008, similar to 2006. Three reported outages involving 500 kV facilities in SERC and WECC occurred during the three-year period.

NERC's Reliability Standard FAC-003[28] requires entities to maintain clearance around transmission lines in order to avoid vegetation-related transmission outages.

Figure 13: Vegetation-Related Transmission Outages: Summer Months, 2006-2008



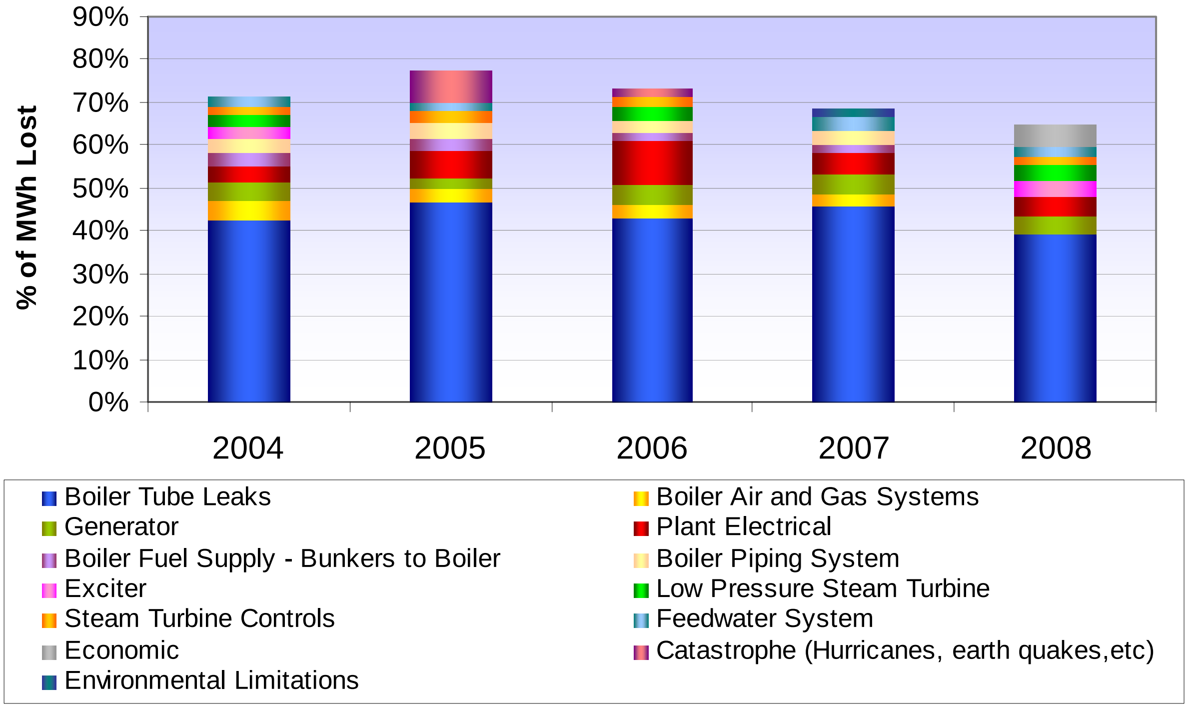
[28] http://www.nerc.com/files/FAC-003-1.pdf

2. Fossil-Fired Generation Outages

Currently, NERC collects data on generating plant outages throughout North America through its voluntary Generating Availability Data System (GADS). Figure 14 compares the most prominent causes of forced outages for fossil-fired steam generating units in the U.S. This comparison is measured as a percentage of megawatt-hours (MWh) lost for each cause, subsequently normalized by MWh lost by all fossil-fired units for each of the years 2004 through 2008. Based on this comparison, boiler tube leaks represented nearly 40 percent of all MWh lost due to forced outages.[29]

The significant rise in "economic" outages seen in the 2008 summer season were mostly due to several events in Pennsylvania and Maryland, when generators were unable to schedule day-ahead gas contracts with suppliers.

Figure 14: Top Causes of Fossil-Fired Generating Unit Outages as a Percent of MWh Lost: Summer Months, 2004-2008



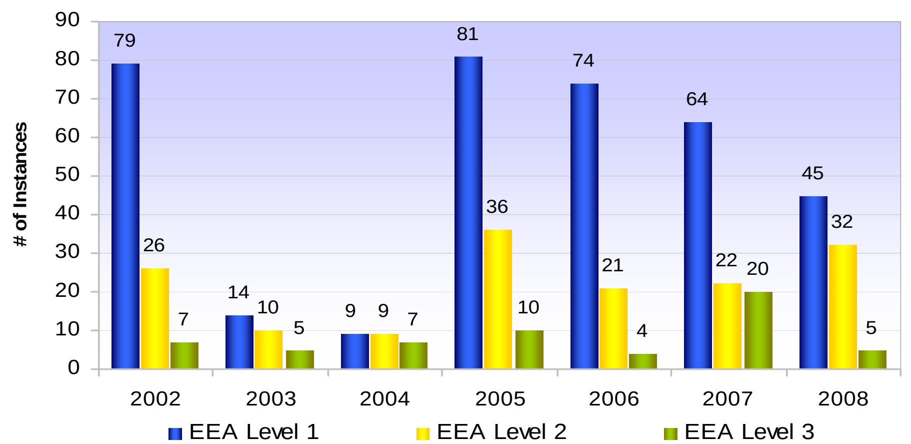
[29] A comprehensive analysis of GADS data was not performed for this assessment. The information presented here is illustrative of the data available in GADS. Therefore, it is presented here for informational purposes only.

3. Energy Emergency Alerts

Figure 15 displays resource adequacy events for declared capacity and energy emergencies for the 2002 through 2008 summer seasons. Energy Emergency Alerts (EEA) indicate insufficient supply is available to meet demand within a balancing area, and typically occur during the summer months. See the call-out box below for definitions of EEA severity levels.

While EEA Level 1 events declined from 2005 to 2008, EEA Level 2 events reached their second highest level of the seven-year period during the 2008 summer season.[30] Level 3 events were lower in 2008 compared to the 2007 summer season.

Figure 15: EEA Peak Levels 2002-2008: June-August



Energy Emergency Alert Levels:

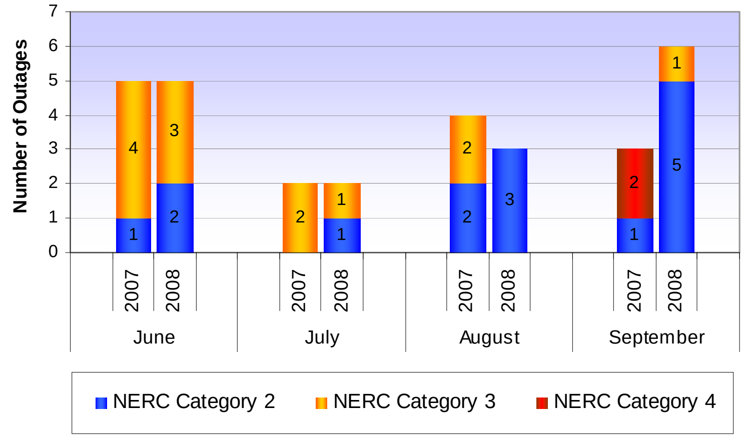
- **Level 1 — All available resources in use.**
  - Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- **Level 2 — Load management procedures in effect**.
  - Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
  - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to: Public appeals to reduce demand, Voltage reduction, Interruption of non-firm end use loads in accordance with applicable contracts, Demand-side management, and Utility load conservation measures.
- **Level 3 — Firm load interruption imminent or in progress**.
  - Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

[30] The categories for capacity and emergency events based on Standard EOP-002-0, require revision to account for higher use of demand response as a dispatch able capacity resource. EEA Level 2 alerts increased in 2008, which may be related to higher levels of demand response. The current definitions for Category A2 include the operation of demand-side resources as a capacity and emergency events, while current industry practice includes them as part of normal, non-emergency operations. The Reliability Fundamentals Working Group is refining these definitions (http://www.nerc.com/files/EOP-002-2.pdf).

4. Disturbance Events

Bulk Power System Disturbances are shown in Figure 16 for the summer months of 2007 and 2008 by category (see call out box below). July has the fewest outages (two) for both the 2007 and 2008 summer seasons; more outages appear to occur in the June and September months.

Figure 16: Disturbance Events by NERC Category: Summer Months, 2007-2008



System protection misoperations have been a leading cause of disturbance events.[31] These misoperations contributed to over 45 percent of the bulk power system disturbances in calendar year 2007. NERC continues to monitor the causes and impacts of system protection misoperations and has a number of activities underway to address this issue as part of its System Protection Initiative.

NERC Bulk Power System Disturbance Classification Scale

Category 1: An event results in any or combination of the following actions:

a. the loss of a bulk power transmission component beyond recognized criteria, i.e. single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
b. frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.
c. frequency above the High FTL more than 5 minutes.
d. partial loss of dc converter station (mono-polar operation)
e. inter-area oscillations

Category 2: An event results in any or combination of the following actions:

a. the loss of multiple bulk power transmission components.
b. the loss of load (less than 500 MW)
c. system separation with loss of less than 5,000 MW load or generation.
d. SPS or RAS misoperation
e. the loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the ERCOT or Québec Interconnections).
f. the loss of an entire generation station or 5 or more generators.
g. the loss of an entire switching station (all lines, 100 kV or above).
h. complete loss of dc converter station.

Category 3: An event results in any or combination of the following actions:

a. the loss of generation (2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT or Québec Interconnections).
b. the loss of load (from 500 to 1,000 MW)
c. system separation or islanding with loss of 5,000 MW to 10,000 MW of load or generation.
d. UFLS or UVLS operation.

Category 4: An event results in any or combination of the following actions:

a. system separation or islanding of more than 10,000 MW of load
b. the loss of load (1,000 to 9,999 MW)

Category 5: An event results in any or combination of the following actions:

a. the occurrence of an uncontrolled or cascading blackout
b. the loss of load (10,000 MW or more)

[31] These metrics are still under development and have not been vetted by the industry. Therefore, these metrics should not be used to draw any conclusions about projected reliability for the summer of 2009.

Assessment Background

The *2009 Summer Reliability Assessment* represents NERC's independent judgment of the reliability of the bulk power system in North America for the 2009 summer season (Table 2).[32] The report specifically provides a high-level reliability assessment of 2009 summer resource adequacy and operating reliability, an overview of projected electricity demand growth, regional highlights, and regional self-assessments.

Table 2: NERC's Annual Assessments		
Assessment	**Outlook**	**Published**
Summer Assessment	Upcoming season	May
Long-Term Assessment	10 year	October
Winter Assessment	Upcoming season	November

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 assessment process enables bulk power system users, owners, and operators to systematically document their operational preparations for the coming season and exchange vital system reliability information. This assessment is prepared by NERC in its capacity as the Electric Reliability Organization.[33] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[34] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

Report Preparation

NERC prepared the *2009 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 data and information submitted by each of the eight Regional Entities in March 2009 and updated, as required, throughout the drafting process. Any other data sources consulted by NERC staff in the preparation of this document are identified in the report.

NERC's staff performed detailed data checking on the reference information received by the Regions, as well as review of all self-assessments to form its independent view and assessment of the reliability of the 2009 summer season. NERC also uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject matter expertise from many sectors of the industry. This process also provides an

[32] 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.
[33] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."
[34] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

essential check and balance for ensuring the validity of the information provided by the regional entities.

Each Region prepares a self-assessment, which is assigned to three or four RAS members, including NERC Operating Committee (OC) liaisons, from other regions for an in-depth and comprehensive review. Reviewer comments are discussed with the Regional Entity's representative and refinements and adjustments are made as necessary. The Regional self-assessments are then subjected to scrutiny and review by the entire subcommittee. This review ensures members of the subcommittee are fully convinced that each Regional self-assessment is accurate, thorough, and complete.

The PC endorses the report for NERC's Board of Trustee (BOT) approval, considering comments from the OC. The entire document, including the Regional self-assessments, is then reviewed in detail by the Member Representatives Committee (MRC) and NERC management before being submitted to NERC's BOT for final approval.

In the *2009 Summer Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[35]

- Supply and demand projections are based on industry forecasts submitted in March 2009. Any subsequent demand forecast or resource plan changes may not be fully represented.
- Peak demand and reserve margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned; planned outages take place as scheduled.
- Demand reductions expected from demand response programs will yield the forecast results, if they are called on.
- Other peak demand-side management programs are reflected in the forecasts of net internal demand.

Enhancements to the 2009 Summer Reliability Assessment

In light of the guidance in FERC's Order 672 and comments received from other authorities and industry representatives, NERC's Planning Committee (PC) concluded the seasonal and Long-Term Reliability Assessment processes required improvement. To achieve this goal, the PC formed a task force, the Reliability Assessment Improvement Task Force, and directed it to develop recommendations and a plan for improvement.

[35] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50 percent probability that actual demand will be higher than the forecast midpoint and a 50 percent probability that it will be lower (50/50 forecast).

A number of the task force's recommendations[36] were incorporated in to the *2009 Summer Reliability Assessment*, including:

1. The Reliability Assessment Guidebook Task Force released its *Reliability Assessment Guidebook* (Version 1.2), [37] to provide increased transparency on the reliability assessments process, resource reporting, load forecasting, and general assumptions made in NERC's Assessments. Regions referenced the guidebook to enhance their contributions to this report.
2. In order to improve data accuracy, NERC has implemented improved data checking methods. A brief summary of these data checking methods is summarized in the *Data Checking Methods Applied* Section.
3. In order to broaden stakeholder input, OC involvement was incorporated to support the assessment development and approval process.
4. Supply categories have been enhanced for 2009 to better assess capacity. Notably, this assessment uses the following supply categories: "Existing, Certain," "Existing, Other" and "Existing, but Inoperable." A brief summary of these terms are provided in the *Resources, Demand and Reserve Margins* Section.
5. "Reserve Margin" replaces "Capacity Margin" used in the 2008 Summer Assessment to be consistent with industry practices and reduce confusion. An explanation for this change is provided in the *Capacity Margin to Reserve Margin Changes* Section.

[36] See http://www.nerc.com/files/Reliability%20Improvement%20Report%20RAITF%20100208.pdf
[37] For the *Reliability Assessment Guidebook*, Version 1.2, see http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf

Estimated Demand, Resources, and Reserve Margins

To improve consistency and increase granularity and transparency, the PC approved new categories[38] for capacity resources, purchases, and sales (see Table 3). The resource designations of "Existing, Certain", "Existing, Uncertain", and "Planned" have been replaced with:

1. **Existing:**
   a. **Existing, Certain** — Existing generation resources available to operate and deliver power within or into the region during the period of analysis in the assessment.
   b. **Existing, Other** — Existing generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons.
   c. **Existing, but Inoperable** — Existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment.

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

The monthly estimates of peak-demand, resources and reserve margins for each Region during the 2009 summer season are in Table 4.[39]

Table 3: Demand, Capacity, and Margins

Total Internal Demand (MW) — The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. Total Internal Demand includes adjustments for indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, and all non-dispatchable demand response programs

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

Existing, Certain and Net Firm Transactions (MW) — Existing, Certain capacity resources plus Firm Imports, minus Firm Exports.

Deliverable Capacity Resources (MW) — Existing, Certain and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports

Prospective Capacity Resources (MW) — Deliverable Capacity Resources plus Existing, Other capacity resources, minus all Existing, Other deratings (includes derates from variable resources, energy only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future, Other capacity resources, minus all Future, Other deratings.

Existing-Certain and Net Firm Transactions (%) — Existing, Certain, and Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Deliverable Capacity Reserve Margin (%) — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Prospective Capacity Reserve Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

NERC Reference Reserve Margin Level (%) – Either the Target Capacity Margin provided by the region/subregion or NERC assigned based on capacity mix (i.e. thermal/hydro).

[38] See the section entitled "*Reliability Concepts Used in this Report*" for definitions that are more detailed.
[39] For the Region of ERCOT, and the subregions of NPCC and RFC, coincided peaks are provided.

Table 4a: Estimated June 2009 Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Reserve Margin (%)	Prospective Capacity Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	57,041	55,926	68,951	70,250	70,250	23.3%	25.6%	25.6%	12.5%
FRCC	43,592	40,424	50,522	51,885	51,885	25.0%	28.4%	28.4%	15.0%
MRO	41,097	38,266	47,559	48,867	48,868	24.3%	27.7%	27.7%	15.0%
NPCC	58,022	54,257	70,209	72,753	72,910	29.4%	34.1%	34.4%	15.0%
New England	24,570	24,570	33,475	33,607	33,764	36.2%	36.8%	37.4%	15.0%
New York	33,452	29,687	36,734	39,146	39,146	23.7%	31.9%	31.9%	15.0%
RFC	166,200	158,000	213,100	213,100	214,400	34.9%	34.9%	35.7%	15.0%
RFC-MISO	57,900	56,200	70,800	70,800	72,100	26.0%	26.0%	28.3%	15.4%
RFC-PJM	108,200	101,700	142,300	142,300	142,300	39.9%	39.9%	39.9%	15.0%
SERC	186,157	180,242	242,221	242,223	255,768	34.4%	34.4%	41.9%	15.0%
Central	39,451	37,800	51,026	51,028	52,673	35.0%	35.0%	39.3%	15.0%
Delta	25,567	24,902	38,735	38,735	38,954	55.5%	55.5%	56.4%	15.0%
Gateway	16,499	16,399	20,857	20,857	20,857	27.2%	27.2%	27.2%	12.7%
Southeastern	45,784	44,069	57,949	57,949	67,704	31.5%	31.5%	53.6%	15.0%
VACAR	58,856	57,072	73,654	73,654	75,580	29.1%	29.1%	32.4%	15.0%
SPP	40,223	39,456	49,298	49,719	55,886	24.9%	26.0%	41.6%	15.0%
WECC	130,198	126,030	169,992	171,733	171,733	34.9%	36.3%	36.3%	14.0%
AZ-NM-SNV	28,170	27,551	36,259	36,451	36,451	31.6%	32.3%	32.3%	13.3%
CA-MX US	54,579	51,853	64,445	65,658	65,658	24.3%	26.6%	26.6%	15.3%
NWPP	36,883	36,343	56,436	56,486	56,486	55.3%	55.4%	55.4%	13.5%
RMPA	10,566	10,283	12,812	13,112	13,112	24.6%	27.5%	27.5%	11.8%
Total-U.S.	722,530	692,601	911,852	920,530	941,700	31.7%	32.9%	36.0%	15.0%
Canada									
MRO	6,245	5,972	7,330	8,103	8,103	22.7%	35.7%	35.7%	10.0%
NPCC	48,504	48,069	61,788	62,805	64,456	28.5%	30.7%	34.1%	15.0%
Maritimes	3,571	3,136	5,684	5,684	5,684	81.3%	81.3%	81.3%	15.0%
Ontario	24,058	24,058	25,237	26,153	27,649	4.9%	8.7%	14.9%	17.5%
Quebec	20,875	20,875	30,867	30,968	31,123	47.9%	48.3%	49.1%	10.0%
WECC	17,486	17,484	22,112	22,397	22,397	26.5%	28.1%	28.1%	11.3%
Total-Canada	72,235	71,525	91,230	93,305	94,956	27.6%	30.5%	32.8%	10.0%
Mexico									
WECC CA-MX Mex	1,972	1,972	2,288	2,288	2,288	16.0%	16.0%	16.0%	14.3%
Total-NERC	796,737	766,098	1,005,370	1,016,123	1,038,944	31.2%	32.6%	35.6%	15.0%

Table 4b: Estimated July 2009 Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Reserve Margin (%)	Prospective Capacity Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	60,618	59,503	69,881	72,362	72,362	17.4%	21.6%	21.6%	12.5%
FRCC	45,091	41,914	50,908	52,271	52,271	21.5%	24.7%	24.7%	15.0%
MRO	43,539	40,641	47,514	48,815	48,837	16.9%	20.1%	20.2%	15.0%
NPCC	61,327	57,562	70,232	72,872	73,029	22.0%	26.6%	26.9%	15.0%
New England	27,875	27,875	33,475	33,703	33,860	20.1%	20.9%	21.5%	15.0%
New York	33,452	29,687	36,757	39,169	39,169	23.8%	31.9%	31.9%	15.0%
RFC	178,100	169,900	213,100	213,100	214,400	25.4%	25.4%	26.2%	15.0%
RFC-MISO	61,800	60,100	70,800	70,800	72,100	17.8%	17.8%	20.0%	15.4%
RFC-PJM	116,200	109,700	142,300	142,300	142,300	29.7%	29.7%	29.7%	15.0%
SERC	201,364	195,211	243,309	243,311	257,066	24.6%	24.6%	31.7%	15.0%
Central	42,733	40,874	50,645	50,647	52,290	23.9%	23.9%	27.9%	15.0%
Delta	26,989	26,319	38,727	38,727	38,975	47.1%	47.1%	48.1%	15.0%
Gateway	19,065	18,946	20,663	20,663	20,699	9.1%	9.1%	9.3%	12.7%
Southeastern	49,009	47,294	59,364	59,364	69,117	25.5%	25.5%	46.1%	15.0%
VACAR	63,568	61,778	73,910	73,910	75,985	19.6%	19.6%	23.0%	15.0%
SPP	43,794	43,027	49,298	49,719	55,886	14.6%	15.6%	29.9%	15.0%
WECC	140,852	136,562	171,743	173,439	173,439	25.8%	27.0%	27.0%	14.0%
AZ-NM-SNV	30,505	29,896	36,241	36,419	36,419	21.2%	21.8%	21.8%	13.3%
CA-MX US	59,103	56,306	64,834	67,313	67,313	15.1%	19.5%	19.5%	15.3%
NWPP	39,740	39,141	57,815	56,568	56,568	47.7%	44.5%	44.5%	13.5%
RMPA	11,504	11,219	12,813	13,113	13,113	14.2%	16.9%	16.9%	11.8%
Total-U.S.	774,685	744,320	915,985	925,889	947,291	23.1%	24.4%	27.3%	15.0%
Canada									
MRO	6,382	6,109	7,510	8,276	8,276	22.9%	35.5%	35.5%	10.0%
NPCC	49,211	48,772	65,609	67,487	68,282	34.5%	38.4%	40.0%	15.0%
Maritimes	3,513	3,074	5,671	5,671	5,671	84.5%	84.5%	84.5%	15.0%
Ontario	24,998	24,998	28,010	29,787	30,409	12.0%	19.2%	21.6%	17.5%
Quebec	20,700	20,700	31,928	32,029	32,202	54.2%	54.7%	55.6%	10.0%
WECC	18,071	18,071	23,227	23,484	23,484	28.5%	30.0%	30.0%	11.3%
Total-Canada	73,664	72,952	96,346	99,247	100,042	32.1%	36.0%	37.1%	10.0%
Mexico									
WECC CA-MX Mex	2,084	2,084	2,287	2,387	2,387	9.7%	14.5%	14.5%	14.3%
Total-NERC	850,433	819,356	1,014,618	1,027,522	1,049,720	23.8%	25.4%	28.1%	15.0%

Table 4c: Estimated August 2009 Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Reserve Margin (%)	Prospective Capacity Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	64,218	63,103	70,626	73,107	73,107	11.9%	15.9%	15.9%	12.5%
FRCC	45,734	42,531	50,510	51,873	51,873	18.8%	22.0%	22.0%	15.0%
MRO	43,431	40,505	47,523	48,824	48,846	17.3%	20.5%	20.6%	15.0%
NPCC	61,327	57,562	70,210	72,850	73,007	22.0%	26.6%	26.8%	15.0%
New England	27,875	27,875	33,475	33,703	33,860	20.1%	20.9%	21.5%	15.0%
New York	33,452	29,687	36,735	39,147	39,147	23.7%	31.9%	31.9%	15.0%
RFC	172,600	164,400	213,100	213,100	214,400	29.6%	29.6%	30.4%	15.0%
RFC-MISO	62,500	60,800	70,800	70,800	72,100	16.4%	16.4%	18.6%	15.4%
RFC-PJM	110,000	103,500	142,300	142,300	142,300	37.5%	37.5%	37.5%	15.0%
SERC	200,265	194,155	243,706	243,708	257,505	25.5%	25.5%	32.6%	15.0%
Central	41,968	40,174	50,629	50,631	52,270	26.0%	26.0%	30.1%	15.0%
Delta	27,865	27,170	39,203	39,203	39,493	44.3%	44.3%	45.4%	15.0%
Gateway	19,024	18,905	20,645	20,645	20,687	9.2%	9.2%	9.4%	12.7%
Southeastern	49,504	47,789	59,340	59,340	69,093	24.2%	24.2%	44.6%	15.0%
VACAR	61,904	60,117	73,889	73,889	75,962	22.9%	22.9%	26.4%	15.0%
SPP	44,342	43,575	49,298	49,719	55,886	13.1%	14.1%	28.3%	15.0%
WECC	141,019	136,768	170,664	172,353	172,353	24.8%	26.0%	26.0%	14.0%
AZ-NM-SNV	30,228	29,625	36,272	36,478	36,478	22.4%	23.1%	23.1%	13.3%
CA-MX US	61,237	58,421	64,861	67,358	67,358	11.0%	15.3%	15.3%	15.3%
NWPP	38,421	37,876	56,680	55,380	55,380	49.6%	46.2%	46.2%	13.5%
RMPA	11,133	10,846	12,810	13,110	13,110	18.1%	20.9%	20.9%	11.8%
Total-U.S.	772,937	742,600	915,637	925,534	946,978	23.3%	24.6%	27.5%	15.0%
Canada									
MRO	6,325	6,052	7,588	8,354	8,354	25.4%	38.0%	38.0%	10.0%
NPCC	48,677	48,233	64,588	66,466	67,339	33.9%	37.8%	39.6%	15.0%
Maritimes	3,497	3,053	5,733	5,733	5,733	87.8%	87.8%	87.8%	15.0%
Ontario	24,192	24,192	28,206	29,983	30,687	16.6%	23.9%	26.8%	17.5%
Quebec	20,988	20,988	30,649	30,750	30,919	46.0%	46.5%	47.3%	10.0%
WECC	17,730	17,730	23,321	23,578	23,578	31.5%	33.0%	33.0%	11.3%
Total-Canada	72,732	72,015	95,497	98,398	99,271	32.6%	36.6%	37.8%	10.0%
Mexico									
WECC CA-MX Mex	2,115	2,115	2,287	2,437	2,437	8.1%	15.2%	15.2%	14.3%
Total-NERC	847,783	816,729	1,013,421	1,026,369	1,048,686	24.1%	25.7%	28.4%	15.0%

Table 4d: Estimated September 2009 Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Reserve Margin (%)	Prospective Capacity Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	50,407	49,292	70,292	72,818	72,818	42.6%	47.7%	47.7%	12.5%
FRCC	43,689	40,515	47,792	49,292	49,292	18.0%	21.7%	21.7%	15.0%
MRO	40,160	37,427	47,373	48,694	47,938	26.6%	30.1%	28.1%	15.0%
NPCC	55,522	51,757	64,590	67,230	67,387	24.8%	29.9%	30.2%	15.0%
New England	22,070	22,070	33,475	33,703	33,860	51.7%	52.7%	53.4%	15.0%
New York	33,452	29,687	31,115	33,527	33,527	4.8%	12.9%	12.9%	15.0%
RFC	152,600	144,400	213,100	213,100	214,400	47.6%	47.6%	48.5%	15.0%
RFC-MISO	53,200	51,500	70,800	70,800	72,100	37.5%	37.5%	40.0%	15.4%
RFC-PJM	99,300	92,800	142,300	142,300	142,300	53.3%	53.3%	53.3%	15.0%
SERC	182,987	177,111	240,043	240,045	253,674	35.5%	35.5%	43.2%	15.0%
Central	39,434	37,852	50,134	50,136	51,785	32.4%	32.5%	36.8%	15.0%
Delta	25,594	24,909	38,920	38,920	39,234	56.2%	56.2%	57.5%	15.0%
Gateway	16,017	15,917	20,911	20,911	20,911	31.4%	31.4%	31.4%	12.7%
Southeastern	45,469	43,755	58,318	58,318	68,073	33.3%	33.3%	55.6%	15.0%
VACAR	56,473	54,678	71,760	71,760	73,671	31.2%	31.2%	34.7%	15.0%
SPP	38,305	37,538	49,298	49,719	55,886	31.3%	32.4%	48.9%	15.0%
WECC	128,127	124,108	170,074	172,051	172,051	37.0%	38.6%	38.6%	14.0%
AZ-NM-SNV	27,187	26,587	36,192	36,386	36,386	36.1%	36.9%	36.9%	13.3%
CA-MX US	55,949	53,148	64,734	66,261	66,261	21.8%	24.7%	24.7%	15.3%
NWPP	35,240	34,801	56,755	56,725	56,725	63.1%	63.0%	63.0%	13.5%
RMPA	9,751	9,572	12,352	12,652	12,652	29.0%	32.2%	32.2%	11.8%
Total-U.S.	691,797	662,148	902,562	912,949	933,447	36.3%	37.9%	41.0%	15.0%
Canada									
MRO	5,970	5,697	7,132	7,918	7,918	25.2%	39.0%	39.0%	10.0%
NPCC	46,410	45,956	60,570	62,501	64,065	31.8%	36.0%	39.4%	15.0%
Maritimes	3,629	3,175	5,676	5,676	5,676	78.8%	78.8%	78.8%	15.0%
Ontario	22,071	22,071	25,734	27,564	29,015	16.6%	24.9%	31.5%	17.5%
Quebec	20,710	20,710	29,160	29,261	29,374	40.8%	41.3%	41.8%	10.0%
WECC	17,435	17,418	21,899	22,465	22,465	25.7%	29.0%	29.0%	11.3%
Total-Canada	69,815	69,071	89,601	92,884	94,448	29.7%	34.5%	36.7%	10.0%
Mexico									
WECC CA-MX Mex	2,092	2,092	2,287	2,387	2,387	9.3%	14.1%	14.1%	14.3%
Total-NERC	763,704	733,311	994,450	1,008,220	1,030,282	35.6%	37.5%	40.5%	15.0%

Notes for Table 4a through 4d

Note 1: Existing-Certain and Net Firm Transactions and Net Capacity Resources are reported to be deliverable by the regions.

Note 2: The inoperable portion of Total Potential Resources may not be deliverable.

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

Note 4: The demand-side management resources are not necessarily sharable between the WECC subregions and are not necessarily sharable within subregions.

Note 5: WECC CA-MX represents only the northern portion of the Baja California Norte, Mexico electric system interconnected with the U.S.

Note 6: MISO and PJM information does not sum to the RFC total since the RFC total also includes approximately 100 MW of Ohio Valley Electric Corporation (OVEC) peak demand. OVEC is not a member of PJM or MISO.

Note 7: These demand and supply forecasts were reported on March 31, 2009.

Note 8: Each Region/subregion may have their own specific reserve margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned a 15 percent reserve margin for predominately thermal systems and a 10 percent reserve margin for predominately hydro systems. For Capacity Margin comparisons, see Table 5a through 5d in the *Capacity Margin to Reserve Margin Changes* section of this report.

Note 9: Based on MISO tariff requirements, individual LSE reserve levels in the SERC Gateway subregion are 12.7 percent. Accordingly, the NERC Reference Margin Reserve Level for SERC Gateway subregion is 12.7 percent. For more information, see the MISO *2009–10 LOLE Study Report* at http://www.midwestmarket.org/publish/Document/62c6cd_120e7409639_-7f2a0a48324a.

Regional Reliability Assessment Highlights

ERCOT

The current slowdown in economic conditions is reflected in the decrease of ERCOT's peak demand forecast from the 2008 projection for 2009 of 66,247 MW to the current projection for 2009 of 64,218 MW. Market participants in the Region added 3,521 MW of generating capacity since last summer. Together, these changes result in a Deliverable Capacity Reserve Margin of 15.9 percent — above the 12.5 percent minimum reserve margin — indicating that the ERCOT Region is expected to have sufficient resources to serve peak demand in the Region this summer.

There are no known transmission constraints that could significantly impact reliability across the ERCOT Region. The continuing increase of installed wind generation in west Texas is likely to result in transmission congestion within and traveling out of west Texas. Market participants have recently announced their intention to "mothball" or retire several generating units. ERCOT is currently evaluating the need to maintain operation of some of these units through Reliability Must Run agreements to maintain system reliability, though these changes are not expected to impact reliability for the 2009 summer months.

FRCC

FRCC expects to have adequate generating capacity reserves with transmission system deliverability for the 2009 summer peak demand. In addition, Existing, Other merchant plant capability of 1,345 MW is potentially available as Future Resources of FRCC members and others. The transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand and to provide planned firm transmission service. Operational issues in Central Florida can develop due to unplanned outages of generating units serving that area. However, it is anticipated that existing operational procedures, planning, and training will adequately manage and mitigate these potential impacts to the bulk power system.

MRO

The forecast for 2009 summer peak demand is slightly lower than that for 2008 summer due to the North American economic downturn. Since 2008 summer, significant wind generation has been added and one large coal plant has come on line. The combination of reduced demand and increased generation has allowed the forecasted reserve margin to increase above the 2008 summer level and well above target levels within the MRO Region.

Within the MRO Region, the Upper Midwest area is rich in wind resources, of which capacity factors may reach the 40–45 percent range. Four states within the MRO Region have Renewable

Portfolio Standards, which require a percentage of annual energy to be served by renewable resources by a specified year. Two additional states within the Region have renewable portfolio objectives, which are similar to RPS although there are no mandates. Wind generation levels are expected to reach nearly 6,000 MW (nameplate) in summer 2009 for the MRO Region, a 50 percent increase since 2008 summer. The majority of this wind generation is located in the MRO-U.S. footprint. At times, a large percentage of the wind generation simultaneously operates during low demand periods. Most of the installed wind farms are energy-only resources and have operating guides and Special Protection Systems associated with them. Managing the magnitude and variability of wind generation this summer will be an increased challenge for the Midwest ISO Reliability Coordinator and its associated Transmission Operators.

Other than the challenge of operating a large amount of wind generation, there are no reliability concerns anticipated within the MRO Region for 2009 summer.

NPCC

The forecasted coincident peak demand for NPCC during the 2009 peak week is 110,645 MW. The reserve margins for the NPCC summer peaking areas of New York, New England and Ontario have generally increased for most summer months over the corresponding 2008 values. Over 3,200 MW of capacity additions have been made since 2008 summer. In July 2009, TransÉnergie will commission the new Ottawa-area Outaouais interconnection with Ontario across the Ottawa River. The interconnection consists of two 625-MW back-to-back HVdc converters in Québec and a double-circuit 230 kV line to the Hawthorne substation in Ottawa. In New England, significant improvements to the transmission system have been completed or are in progress. They include:

- The remaining components of the Middletown-Norwalk phase of the Southwest Connecticut Reliability Project have been placed in service, improving the area's near-term and mid-term reliability and infrastructure.
- The NSTAR 345 kV Transmission Reliability Project (which helps to relieve some of the constraints that limit Boston imports) is complete.
- The Short-Term Lower SEMA upgrades project is under construction and contains several facilities anticipated to be in service for 2009 summer. This project addresses transmission deficiencies in Lower Southeast Massachusetts and reduces the reliance on local generating units that are committed to address second-contingency protection for the loss of two major 345 kV lines.

RFC

Both RTOs (PJM and MISO) within Reliability*First* are projected to have sufficient reserve margins for the upcoming summer. Therefore, the Reliability*First* Region is expected to have adequate reserves for the 2009 summer. The 2009 coincident peak for the RFC Region is 169,900 MW net internal demand and 178,100 MW total internal demand. The forecast net internal demand peak is 7,800 MW (4.4 percent) lower than the forecast demand for 2008.

A total of 220,000 MW of existing capacity is projected to be available in the RFC Region in summer 2009. This total is 4,200 MW greater than the 215,800 MW reported as existing capacity in last summer's assessment. A large part of this increase (2,900 MW) is due to including the existing Behind-the-Meter generation, which was excluded from last year's reported existing capacity.

The transmission system within the Reliability*First* footprint is expected to perform well over a wide range of operating conditions, provided new facilities go into service as scheduled and transmission operators take appropriate action, as needed, to control power flows, reactive reserves and voltages.

However, it is always possible that a combination of high loads due to adverse weather, coupled with high generating unit outages and the unavailability of additional power purchases from the interconnection, could result in the curtailment of firm demand. Such a curtailment is considered a low-probability event for this summer.

SERC

SERC Reliability Corporation (SERC) reports that all utilities within the Region expect to meet peak demand during the 2009 summer. The 2009 summer demand forecast is 1 percent lower than that reported for 2008 summer. This reduction in demand over last year is primarily due to a slowdown in the economy of the Region and North America as a whole. The majority of the utilities in SERC are forecasting lower demand for 2009 summer than they forecasted a year ago.

Utilities in the SERC Region expect to have adequate generating capacity and reserves necessary to meet all customer requirements during the 2009 summer period. However, the aggregate reserve margin for the utilities in the Gateway subregion is indeterminate at the time of this draft submittal (May 5, 2009). See the Gateway subregion report for more detail.

The transmission capability of the utilities within the SERC Region is expected to be adequate to deliver supply to firm customer demand. Operational issues can develop due to unplanned outages of generating units owned by the companies within the SERC Region, however, it is anticipated that existing operational procedures, pre-planning, and training will allow the utilities in the Region to adequately manage and mitigate the impacts of such events to the bulk transmission system in the Region.

SPP

For the upcoming summer, SPP reports all utilities within the Region expect to meet all customer requirements imposed upon them. The non-coincident total internal demand forecast for the upcoming summer peak is 44,342 MW, which is 2 percent higher than the 2008 actual summer peak non-coincident total internal demand. The actual 2008 summer demand of 43,408 was 0.3 percent lower than the 43,571 summer forecasted projection for 2008. Last year, SPP experienced a slight decrease in demand from the normal forecast due to mild temperatures in the summer. SPP expects to have 58,722 MW of total internal capacity for the upcoming summer season. This consists of Existing Certain Capacity of 49,032 MW, Existing Other Capacity of 8,597 MW, Existing Inoperable Capacity of 597 MW, and Future Capacity of 496 MW.

Based on the evaluated contingency events and taking into consideration transmission operating directives, Southwest Power Pool is not expecting any reliability issues for the upcoming summer. The resources available for the Region are adequate to meet the expected peak demand.

WECC

WECC expects to have adequate generation capacity, reserves and transmission for the forecasted 2009 summer peak demand and energy loads. This is attributed to the combination of a lower demand forecast, additional generation resources, and transmission system enhancements. The aggregate, WECC 2009 summer total internal demand is forecast to be 161,007 MW (U.S. systems 140,966 MW, Canadian systems 18,071 MW, and Mexican system 2,115 MW). The forecast is based on normal weather conditions, and is 4.3 percent above last summer's actual peak demand of 154,327 MW. The 2008 summer peak occurred under normal to somewhat-below-normal temperatures in the Region. The 2009 summer, total internal demand forecast is 0.6 percent less than last summer's forecast peak demand of 162,052 MW for the 2008 summer period. The decline in the forecast peaks can be attributed primarily to the change in economic conditions. The capabilities presented in this assessment reflect plant contingent capacity transfers between subregions, but do not reflect other expected firm and non-firm transactions within the WECC Region.

Regional Reliability Self-Assessments

INTRODUCTION

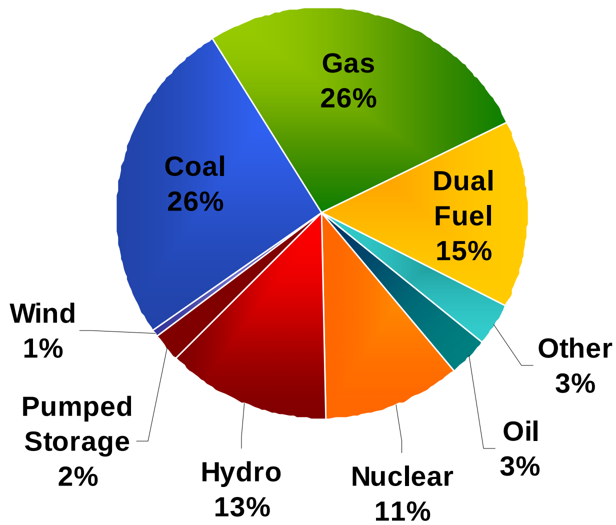
Regional Resource and Demand Projections

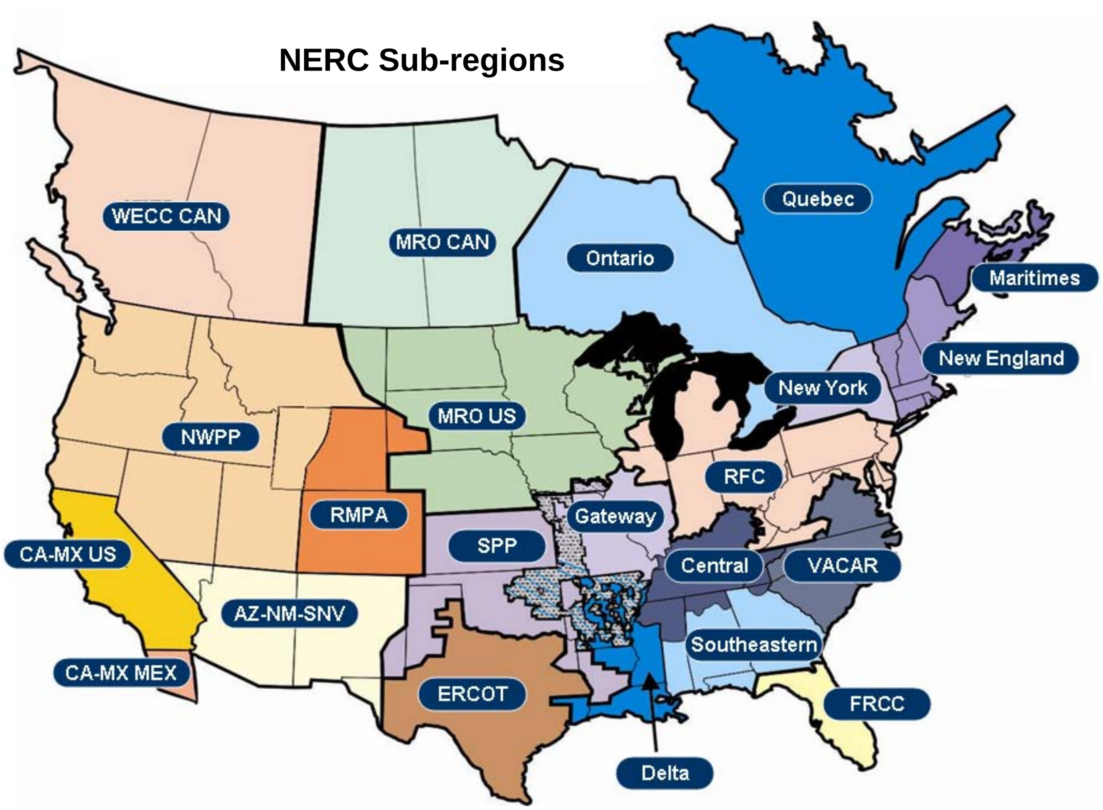
The figures in the regional self-assessment pages show the regional historical demand, projected demand and growth, reserve margin projections, and generation expansion projections reported by the regions.

Capacity Fuel Mix

The regional capacity fuel mix charts show each Region's relative reliance on specific fuels[40] for its reported generating capacity. The charts for each Region in the Regional self-assessments are based on the most recent data available in NERC's Electricity Supply and Demand (ES&D) database.

Figure 17: NERC Relative Capacity by Fuel Mix





[40] Note: The category "Other" may include capacity for which the total capacity of a specific fuel type is less than 1% of the total capacity or the fuel type has yet to be determined

ERCOT

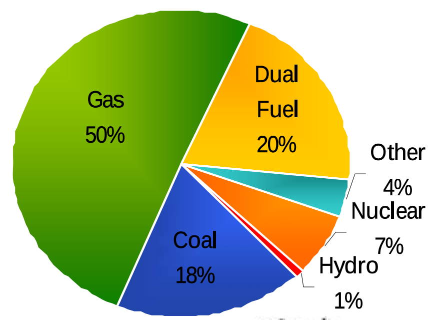
Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	64,218
Direct Control Load Management	0
Contractually Interruptible (Curtailable)	0
Critical Peak-Pricing with Control	0
Load as a Capacity Resource	1,115
Net Internal Demand	63,103

2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	63,702	-0.9%
2008 Summer Actual Peak Demand	62,266	1.3%
All-Time Summer Peak Demand	62,339	1.2%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	70,626	11.9%
Deliverable Capacity Resources	73,107	15.9%
Prospective Capacity Resources	73,107	15.9%
NERC Reference Margin Level	-	12.5%

On-Peak Capacity by Fuel Type



Introduction

The current slowdown in economic conditions is reflected in the decrease of the peak demand forecast for ERCOT from the 2008 projection for 2009 of 66,247 MW to the current projection for 2009 of 64,218 MW. Market participants in the Region added 3,521 MW of generating capacity since last summer. Together, these changes result in a Deliverable Capacity Reserve Margin of 15.9 percent — above the 12.5 percent minimum reserve margin — indicating the ERCOT Region is expected to have sufficient resources to serve its peak demand this summer.

There are no known transmission constraints that could significantly impact reliability across the ERCOT Region. The continuing increase of installed wind generation in west Texas is likely to result in transmission congestion within and out of west Texas. Market participants have recently announced their intention to mothball or retire several generating units. ERCOT is currently evaluating the need to maintain operation of some of these units through Reliability Must Run agreements to maintain system reliability.

Demand

The 2008 summer actual peak demand for the ERCOT Region was 62,179 MW. This peak demand was set with relatively mild temperatures in August (below normal). In 2008, the summer peak demand forecast for 2009 was 66,247 MW. The current forecast for the 2009 summer peak demand is 64,218 MW, which is lower than last year's forecast for 2009, primarily due to lower projections for the underlying economic drivers.

The average weather profile (50/50) is used for the ERCOT load forecast. The economic factors, which drive the load forecast, include per capita income, population, gross domestic product (GDP), and various employment measures that include non-farm employment and total employment. The actual demands used for forecasting purposes are coincident hourly values across the ERCOT Region. The data used in the forecast is differentiated by weather zones.

The forecasted peak demands are produced by the ERCOT ISO for the entire Region, based on the Region-wide actual demands. While the forecasted peak demands produced using the average weather profile are used to make resource assessments, alternative weather scenarios are used to develop extreme weather load forecasts to assess the impact of weather variability on the peak demand for ERCOT. One scenario is the one-in-ten-year occurrence of a weather event. This scenario is calculated using the 90th percentile of the temperatures in the database spanning the last 13 years available. These extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The extreme temperature assumptions consistently produce demand forecasts that are approximately 5 percent higher than the forecasts based on the average weather profile (50/50). Together, the forecasts from these temperature scenarios are usually referred to as 90/10 scenario forecasts.

Texas state law[41] mandates that at least 20 percent of an investor-owned utility's (IOU's) annual growth in electricity demand for residential and commercial customers shall be met through energy efficiency programs each year. IOUs are required to administer energy savings incentive programs, which are implemented by retail electric and energy efficiency service providers. Some of these programs, offered by the utilities, are designed to produce system peak demand reductions and energy consumption savings and include the following: commercial and industrial; residential and small commercial; hard-to-reach; load management; energy efficiency improvement programs; low income weatherization; energy star (new homes); air conditioning; air conditioning distributor; air conditioning installer training; retro-commissioning; multifamily water and space heating; Texas SCORE/City Smart; trees for efficiency; and third party contracts.

In general, utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities. In the latest assessment, utility programs implemented after electric utility industry restructuring in Texas had produced 756 MW of peak demand reduction and 2,005 GWh of electricity savings for the years 1999 though 2006. Most of the effect of this demand reduction is accounted for within the load forecast and only the incremental portion is included as a separate demand adjustment.

Loads acting as a Resource (LaaRs) providing Responsive Reserve Service provide an average of approximately 1115 MW of dispatchable, contractually committed demand response during summer peak hours based on the most recently available data. LaaRs are considered an offset to peak demand and contribute to the reserve margin.

ERCOT's Emergency Interruptible Load Service (EILS), is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "firm" load, and represents contractually committed interruptible load. EILS is not considered an offset to net demand and

[41] http://www.capitol.state.tx.us/tlodocs/80R/billtext/html/HB03693F.htm

does not contribute to reserve margins. Based on average EILS commitments during 2008, approximately 217 MW of EILS load can be counted upon during summer peaks.

Generation

Currently, ERCOT has 70,028 MW of Existing Certain generation, approximately 8,128 MW Existing Other generation, and 2,526 MW Future Planned capacity expected to go into service prior to or during the 2009 summer season.

ERCOT has existing wind generation nameplate capacity totaling 8,065 MW; however, only 8.7 percent is included in the Existing, Certain amount used for reserve margin calculations, based on a study of the effective load-carrying capability (ELCC) [42] of wind generation in the Region. The remaining existing wind capacity amount is included in the Existing, Other generation amount. Of the Existing, Certain amount, 48 MW is biomass (wood waste) and an additional 45 MW of biomass is included in the Future Planned capacity.

There are 3,112 MW of Existing capacity considered inoperable due to its mothballed status. Two market participants have recently announced plans to mothball or retire an additional 3,732 MW of older gas generation; the portion of this capacity that is retired prior to 2009 summer has been removed from the Existing generation and the portion that is being mothballed prior to 2009 summer is included only in the Existing, Inoperable amount. ERCOT is still evaluating the need to establish a Reliability Must Run contract with two of the generating units, totaling 630 MW, due to local transmission reliability requirements; until a contract is signed for these units, their capacity has been excluded from the reserves calculation.

Before a new power project is included in reserve margin calculations,[43] a binding interconnection agreement must exist between the resource owner and the transmission service provider. Additionally, thermal units must have an air permit specifying the conditions for operation issued from the appropriate state and federal agencies. Future capacity that will be available for 2009 summer includes 1,004 MW of gas-fired generation, 1436 MW from coal, 45 MW of biomass, and 475 MW from wind turbines. Of that 475 MW, 41 MW (8.7 percent) contributes to reserve margin calculations.

Capacity Transactions on Peak

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

[42] http://www.ercot.com/content/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin_Analysis_Report.pdf

[43] http://www.ercot.com/content/meetings/tac/keydocs/2007/0330/11._Draft_GATF_Report_to_TAC_-_Revision_2.doc

For the 2009 summer season, ERCOT has 458 MW of imports from SPP and 140 MW from CFE. Of the imports from SPP, 48 MW is tied to a long-term contract for purchase of firm power from specific generation. The remaining imports of 410 MW from SPP and 140 MW from CFE represent one-half of the asynchronous tie transfer capability, included due to emergency support arrangements.

A SPP member's ownership of a 247 MW power plant located in ERCOT results in an import to SPP.

While the three asynchronous ties with CFE have previously been available for reliability support, arrangements have been completed so these ties became available for commercial transactions on March 12, 2009.

There are no non-firm contracts signed or pending. There are also no other known contracts under negotiation or under study.

Transmission

Approximately 22 miles of new and 13 miles of rebuilt 345 kV transmission lines were completed since the 2008 summer. Approximately 137 miles of rebuilt 138 kV transmission lines has been completed since 2008 summer and an additional 43 miles of new and 166 miles of rebuilt 138 kV transmission lines are expected to be complete before the 2009 summer period begins. Approximately 70 miles of rebuilt 69 kV transmission lines has been completed since 2008 summer and an additional 81 miles of rebuilt 69 kV is anticipated before the 2009 summer. There are no concerns in meeting the target in-service dates of the projects.

There are no known transmission constraints that could significantly impact reliability across the ERCOT Region. The continued rapid installation of new wind generation in West Texas is expected to result in congestion on multiple constraints within and out of West Texas for the next several years until new bulk transmission lines are added between West Texas and the rest of the ERCOT system.

The following tables show the significant transmission additions completed or planned to be completed to support bulk power system reliability this summer.

Table ERCOT - 1: Transmission Projects

Transmission Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/ Status
Singleton Switching Station	345	0	4/9/09	New 345 kV Switching Station/On-schedule

Table ERCOT - 2: Transformer Projects				
Transformer Project Name	**High-Side Voltage (kV)**	**Low Side Voltage (kV)**	**In-service Date(s)**	**Description/ Status**
Seagoville Switch autotransformer replacement	345	138	12/8/09	In-Service
Roanoke Switching Station #1autotransformer replacement	345	138	5/9/09	On-schedule
Tyler Grande 345/138 kV Switching Station	345	138	5/9/09	On-schedule

In addition, two +300/-265 Mvar static VAR compensators (SVCs) are scheduled to be in-service June 2009 at the 138 kV Parkdale substation, located in Dallas, to protect against a voltage collapse at 2009 peak load levels due for a Category C contingency.

Operational Issues (Known or Emerging)

Currently, there are approximately 40 planned unit outages scheduled sometime during the assessment period of June 1st through September 30th which are not expected to result in reliability issues.

ERCOT has not identified any temporary operating measures that may impact reliability during the summer. There are no environmental or regulatory restrictions known at this time that are expected to impact reliability.

There are no low-water level concerns in the ERCOT Region for the assessment period. Anticipated effects of high water temperatures on generation capacity are minor and are not expected to affect reliability. Any operational limits will be reflected in the Seasonal Net Capability values reported to the ERCOT ISO by the Generator Owners. In Day-Ahead and Real-Time Operations, these effects are mitigated through procurement of Ancillary Services and Out of Merit Capacity (OOMC) deployments.

The ERCOT ISO performs an annual review of all Remedial Action Plans (RAPs), Mitigation Plans (MPs), Pre-Contingency Action Plans (PCAPs), and Conditional Remedial Action Plans (RAP-Cs). This includes a review of all current plans as well as the development of new plans as necessary. This review uses a study model for predicted peak operating conditions, and is completed prior to May 1st of every year. In addition, the ERCOT ISO performs a seasonal Voltage Profile study, which is also completed prior to May 1. No unique operational problems have been observed in these studies; however, at the time of this submission, the studies have not been completed.

The total installed wind capacity in the ERCOT Region has increased significantly since last summer. A Renewable Technologies Working Group (RTWG) has been set up to focus activities related to wind integration in the ERCOT Region. The RTWG has produced a work plan for study and resolution of all identified wind integration issues, as well as reports this to the Public Utility Commission of Texas on a quarterly basis.[44]

ERCOT ISO has implemented a centralized wind forecasting system. ERCOT has updated the ancillary service method, used to determine the procured quantities of ancillary services, to account for wind uncertainty in the procurement of ancillary services. These changes allow ERCOT to adjust the amount of Non-Spinning Reserve Service to account for the uncertainty associated with not only load forecasting but wind forecasting as well. The ancillary service method change also accounts for any increase in installed wind capacity in the Regulation Service. ERCOT is actively developing both a probabilistic risk assessment program and wind event forecasting system to further assess the risk associated with high wind penetration during the operations planning timeframe and allow for timely mitigation of the identified risks. ERCOT has implemented voltage ride-through requirements for new wind generation and is studying the benefits of the application of these requirements to existing wind generation. ERCOT has also redefined its congestion zones since 2008 to reflect the sensitivities of zonal control actions upon the expected congested transmission elements due to increased wind penetration.

No unusual operating conditions that could impact reliability for the upcoming summer are anticipated.

Reliability Assessment Analysis

The Deliverable Capacity Reserve Margin for the 2009 summer assessment period is currently projected to be 15.9 percent, which is 3.4 percent higher than the minimum reserve margin level for ERCOT of 12.5 percent. The ERCOT minimum reserve margin target of 12.5 percent is based on Loss-of-Load Expectation (LOLE) analysis of no more than one-day-in-ten-years loss of load based on the latest loss of load probability (LOLP) study.[45] This currently projected reserve margin for 2009 is 1.8 percent lower than the 17.2 percent reserve margin that was projected for 2008 in last year's summer assessment, due to a slight increase in the demand forecast for the peak of 2009 summer from the forecasted peak for 2008 summer. No external resources were required to reach the target margin level for the 2008 or 2009 summer.

The forecasted reserve margin calculation assumes that the LaaRs demand response program reduces the reserves requirement and wind resources contribute only the ELCC (8.7 percent) of their nameplate capacity to meeting the reserves requirement.

ERCOT does not have a formal definition of generation deliverability. However, in the planning horizon, ERCOT ISO performs a security-constrained unit commitment and economic dispatch analysis for the upcoming year. This analysis is performed on an hourly basis for a variety of

[44] http://www.ercot.com/content/meetings/tac/keydocs/2009/0305/09._ERCOT_Report_to_PUCT_-_March_2009_Final_02-26-2009.doc and http://www.ercot.com/content/meetings/tac/keydocs/2009/0305/09._Attachment_A_-_RTWG_Master_Issues_List_Final_02-26-09.xls

[45] http://www.ercot.com/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin_Analysis_Report.pdf

conditions to ensure deliverability of sufficient resources to meet a load level that is approximately 10 percent higher than the expected coincident system peak demand plus operating reserves. Load data for this analysis is based on the non-coincident demands projected by the transmission owners. Operationally, transmission operating limits are adhered to through market-based generation redispatch directed by ERCOT ISO as the balancing authority and reliability coordinator. Operational resource adequacy is also maintained by ERCOT ISO through market-based procurement processes as detailed in Sections 6 and 7 of the ERCOT Protocols.[46]

ERCOT also does not anticipate extreme summer weather to have an impact on fuel supply or delivery. Natural gas fuel supply interruptions are a potential concern during the winter, due to demand for home heating, but these interruptions typically do not occur in the summer. If fuel supply issues become a potential problem they are reported to ERCOT by the affected entity as a resource de-rating or a forced outage. ERCOT does not coordinate directly with the fuel industry; independent generator owners and operators are responsible for their own fuel supply. In the event of forecasted extreme weather and possible fuel curtailments, ERCOT may request fuel capability information from qualified scheduling entities (QSE) that represent generation to better prepare operationally for potential curtailments (See Section 5.6.5 of the ERCOT Protocols.[47]) Specific information that may be requested can be found in the ERCOT Operating Guides.[48] ERCOT has limited hydro resources and does not include hydro generation resources in the analysis of system reliability needs.

A portion of the ERCOT Region is experiencing an extreme drought but this is not currently expected to impact reliability for 2009 summer.

ERCOT has limited interconnections through dc ties with the Eastern Interconnect and Mexico. The maximum imports/export over these ties is 1,100 MW. These ties can be operated at a maximum import and export provided there are no area transmission elements out of service. In the event of a transmission outage in the area of these ties, studies will be run during the outage coordination period for the outages to see if any import/export limits are needed.

ERCOT regularly performs transient dynamics and voltage studies. These studies did not identify any reliability issues related to angular, voltage or oscillatory stability for Category A, B and C contingencies detailed in Table 1 of the TPL Standards. Small signal stability studies are performed as part of a study to set transfer limits between the West and North zones of ERCOT.

Areas of dynamic and static reactive power limitations are Corpus Christi, Houston, Dallas/Ft. Worth (DFW), Rio Grande Valley, South to Houston generation, South to Houston load, North to Houston Generation, and North to Houston load. These areas and mitigation procedures are found in the Operating Procedures 2.4.3.[49] ERCOT plans for a 5 percent voltage stability margin for Category A and B contingencies and a 2.5 percent margin for Category C contingencies.[50]

[46] http://www.ercot.com/mktrules/protocols/current.html
[47] Ibid
[48] http://www.ercot.com/mktrules/guides/operating/index.html
[49] http://www.ercot.com/mktrules/guides/procedures/TransmissionSecurity_V3R89.doc
[50] http://www.ercot.com/mktrules/guides/operating/2007/07/05/05-070107.doc

Regional UVLS program are implemented in the DFW, Houston, and Rio Grande Valley regions to prevent voltage collapse or excessively low network voltage conditions.

Two independent programs provide relief and support for under-frequency events. The LaaRs demand response program provides up to half of ERCOT's Responsive Reserve Service, between 1,150 MW and 1,400 MW of load-shedding automatically triggered when system frequency goes below 59.7 Hz. A system-wide UFLS program provides a backstop that automatically sheds up to 25 percent of system load in three stages should the system frequency go below 59.3 Hz.

No explicit minimum dynamic reactive criteria exist, however reactive margins are maintained in the major metropolitan areas. Two 140 Mvar dynamic reactive devices were installed in the Houston area in 2008 and two 300 Mvar dynamic reactive devices will be installed in the DFW area by June 2009. Planning studies identified a need for the devices to prevent voltage collapse in the DFW area under certain conditions following Category C contingencies. The devices facilitate DFW area voltage recovery without actuation of UVLS schemes for planned conditions.

ERCOT does not have a specific system-wide transient voltage dip criteria. However, the system is normally planned such that voltage dips will not actuate UVLS schemes in major load centers for Category A, B, and C contingencies. Additionally, some TSPs have implemented projects to limit the amount of UVLS activation in major load centers due to Category D contingencies.

There are no known transmission constraints that could significantly impact reliability across the ERCOT Region. If transmission constraints are identified in the operations planning horizon, Remedial Action Plans or Mitigation Plans may be developed to provide for planned responses to maintain the reliability of a localized area. ERCOT ISO performs off-line transient stability studies for specific areas of the Region as needed. The results of these studies are used in real-time and near real-time monitoring of the grid. ERCOT ISO System Operator Procedures describe the process to monitor the system and to prevent voltage collapse. Different scenarios along with MW safety margins are included in the procedures, as are processes to manage the transmission system based on Voltage Stability Assessment Tool (VSAT) results. When actions are taken to manage the transmission system based on VSAT results, VSAT is executed again, to process the new system topology. The ERCOT ISO also closely monitors a West to North oscillatory stability limit and a North to Houston Voltage Stability Limit, as these limits are identified as IROLs for the ERCOT region.

The economic recession currently appears to result in higher reserves for ERCOT in the 2009 summer season due to the reduction in expected demand.

Other Region-specific issues that were not mentioned above

An extremely hot summer resulting in load levels significantly above forecast, higher than normal generation forced outages, or limitation to fuel availability due to financial difficulties of some generation owners that may make it difficult for them to obtain fuel from suppliers are all risk factors that alone or in combination could result in inadequate supply. In the event that occurs, ERCOT will implement its Energy Emergency Alert (EEA) (See Section 5.6.6.1 of the ERCOT Protocols).[51] The EEA plan includes procedures for interruptible load activation, voltage reductions, procurement of emergency energy over the dc ties and ISO-instructed demand response procedures. These procedures are in place and are described in the ERCOT Operating Guides Section 4.5 Energy Emergency Alert (EEA).[52]

Region Description

ERCOT is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. ERCOT is a summer-peaking Region responsible for about 85 percent of the electric load in Texas with an all-time peak demand of 62,339 megawatts in 2006. The Texas Regional Entity (TRE), a functionally independent division of ERCOT Inc., performs the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT Region.

There are 212 Registered Entities, with 326 functions, operating within the ERCOT Region. Within the Region, the ERCOT ISO is registered as the BA, IA, PA, RC, RP, TOP and TSP. Additional information is available on the ERCOT web site.[53]

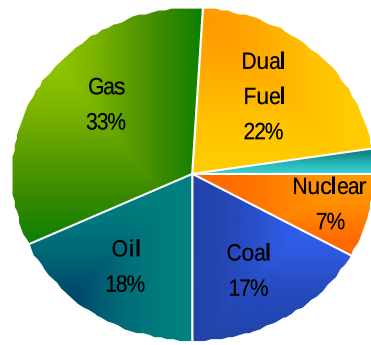
[51] http://www.ercot.com/mktrules/protocols/current.html
[52] http://www.ercot.com/mktrules/guides/operating/current.html.
[53] http://www.ercot.com

FRCC

Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	45,734
Direct Control Load Management	2,452
Contractually Interruptible (Curtailable)	751
Critical Peak-Pricing with Control	0
Load as a Capacity Resource	0
Net Internal Demand	42,531

On-Peak Capacity by Fuel Type



2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	44,417	-4.2%
2008 Summer Actual Peak Demand	44,801	-5.1%
All-Time Summer Peak Demand	46,739	-9.0%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	50,510	18.8%
Deliverable Capacity Resources	51,873	22.0%
Prospective Capacity Resources	51,873	22.0%
NERC Reference Margin Level	-	15.0%

Introduction

FRCC expects to have adequate generating capacity reserves with transmission system deliverability for the 2009 summer peak demand. In addition, Existing, Other merchant plant capability of 1,345 MW is potentially available as Future resources of FRCC members and others.

The transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand and to provide planned firm transmission service. Operational issues in Central Florida can develop due to unplanned outages of generating units serving this area. However, it is anticipated that existing operational procedures, pre-planning, and training will adequately manage and mitigate these potential impacts to the bulk transmission system.

Demand

The Florida Reliability Coordinating Council (FRCC) is forecasted to reach its 2009 summer peak demand of 45,734 MW in August, which represents a projected demand increase of 2.1 percent over the actual 2008 summer demand of 44,801 MW. This projection is consistent with historical weather-normalized FRCC demand growth and is 3.4 percent lower than last year's summer forecast of 47,364 MW. The decrease in the 2009 summer peak demand is attributed to a sluggish economy primarily driven by a declining housing market and higher energy prices.

Each individual Load Serving Entity (LSE) forecast takes into account historical temperatures to determine the normal temperature at the time of peak demand. The demand forecast for this summer takes into consideration the overall economy in Florida with emphasis on the price of fuel and electricity. Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Regional forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the Regional level. The entities within the FRCC Region plan their systems to meet the reserve margin criteria under both summer and winter peak demand conditions.

There are a variety of energy efficiency programs implemented by entities throughout the FRCC Region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates, and high efficiency lighting rebates.[54] The 2009 net internal FRCC peak demand forecast includes the effects of 3,203 MW of potential demand reductions from the use of direct control load management and interruptible load management programs composed of residential, commercial, and industrial demand. Entities within FRCC use different methods to test and verify Direct Load programs such as actual load response to periodic testing, use of a time and temperature matrix and the number of customers participating. Projections also incorporate MW impacts of new energy efficiency programs. There currently is no critical peak pricing with control incorporated into the FRCC projection. Each LSE within the FRCC treats every Demand Side Management load control program as “demand reduction” and not as a capacity resource.

FRCC may assess the peak demand uncertainty and variability by developing Regional bandwidths or 80 percent confidence intervals on the projected or most likely load (90/10). The 80 percent confidence intervals on-peak demand can be interpreted to mean that there is a 10 percent probability that in any year of the forecast horizon that actual observed load could exceed the high band. Likewise, there is a 10 percent probability that actual observed load in any year could be less than the low band in the confidence interval. The purpose of developing bandwidths on-peak demand loads is to quantify uncertainties of demand at the Regional level. This would include weather and non-weather load variability such as demographics, economics, and the price of fuel and electricity. Factors that dampened the growth outlook for this summer’s forecast include a weaker Florida economy and projected higher fuel prices.

Generation

The total Existing generation in the FRCC Region for this summer is 52,162 MW of which 48,276 MW (474 MW of biomass) are Existing-Certain, 131 MW are Inoperable, and 3,755 MW are Other. Since the beginning of the year, a net capacity of 1,500 MW is expected to be online by September 30, 2009. The FRCC Region has a negligible amount of variable generation.

FRCC entities have an “obligation to serve” and this obligation is reflected within each entity’s 10-Year Site Plan filed annually with the Florida Public Service Commission. Therefore, FRCC

[54] Additional details can be found in the 10-Year Site Plan filing for each entity at the following link https://www.frcc.com/Planning/default.aspx?RootFolder=%2fPlanning%2fShared%20Documents%2fTen%20Year%20Site%20Plans%2f2008&FolderCTID=&View=%7bFBDE89E4%2dE66F%2d40EE%2d999D%2dCFF06CF2A726%7

entities consider all Future and Conceptual capacity resources as "Planned" and included in Reserve Margin calculations.

Capacity Transactions on Peak

Currently, there are 2,377 MW of generation under Firm contract available for import into the Region from the Southeastern subregion of SERC. These purchases have firm transmission service to ensure deliverability into FRCC. No Expected or Provisional transactions are included in the assessment.

Presently, the FRCC Region has 143 MW of generation under Firm contract to be exported into the Southeastern subregion of SERC. These sales have firm transmission service to ensure deliverability in the SERC Region. FRCC does not consider Expected or Provisional sales to other Regions as capacity resources.

Transmission

Major additions to the FRCC bulk power system are mostly related to expansion in order to serve the growing demand and therefore maintain the reliability of the transmission system. The most notable transmission additions expected to be in-service for the summer of 2009 include the rebuild of two existing 230 kV transmission lines in the Central Florida area. No other significant substation equipment additions are expected to be available during the summer of 2009.

Table FRCC - 1: Transmission Projects

Transmission Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/ Status
Hobe - Sandpiper	138	8	6/1/09	New line
Brandy Branch - Normandy	230	13	5/31/09	New line
Cane Island - Taft	230	11	6/1/09	Line upgrade
Avon Park - Ft. Meade	230	19	6/1/09	Rebuild

Table FRCC - 2: Transformer Projects

Transformer Project Name	High-Side Voltage (kV)	Low Side Voltage (kV)	In-service Date(s)	Description/ Status
Alico	230	138	12/1/08	New
Pellicer	230	115	5/31/09	New
Midway	230	138	12/1/08	New
Zephyrhills North	230	115	5/31/09	New
Stanton	230	115	5/1/09	New

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

Transmission constraints in Northwest Florida may occur under high imports into Florida from the SERC Region. The FRCC Region and Southeastern subregion of SERC worked together to develop and approve a special operating procedure to address and mitigate these potential constraints.

Operational Issues

There are 2,410 MW of scheduled generating unit maintenance planned for the summer period. No transmission facility maintenance outages of any significance are planned for the summer period. Scheduled transmission outages are typically performed during seasonal off peak periods to minimize any impact on the bulk power system. In addition, there are no foreseen environmental and/or regulatory restrictions or unusual operating conditions that can potentially impact reliability in the FRCC Region during the 2009 summer period.

Although Florida is experiencing drought conditions, cooling water levels and water temperature within the FRCC Region are expected to be in the normal range for 2009 summer and not expected to impact the forecasted reserve margin.

FRCC expects the bulk transmission system to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the summer peak demand. The results of the 2009 Summer Transmission Assessment, which evaluated the steady-state summer peak load conditions under different operating scenarios, indicates that any concerns with thermal overloads or voltage conditions can be managed successfully by operator intervention. Such interventions may include generation redispatch, system sectionalizing, reactive device control, and transformer tap adjustments. The operating scenarios analyses included the unavailability of major generating units within FRCC. Therefore, various dispatch scenarios were evaluated to ensure generating resources within FRCC are deliverable by meeting NERC Reliability Standards under these operating scenarios. No operational changes are needed due to the integration of variable resources for the 2009 summer.

No unusual operating conditions are expected that could impact reliability for the upcoming 2009 summer. FRCC has a Reliability Coordinator agent that monitors real-time system conditions and evaluates near-term operating conditions of the bulk power grid. The Reliability Coordinator uses a Region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are provided with new input data from operating members every ten seconds. These tools enable the FRCC Reliability Coordinator to implement operational procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments to successfully mitigate line loading and voltage concerns that may occur in real time.

Reliability Assessment Analysis

The FRCC Region is required by the State of Florida to maintain a 15 percent reserve margin (20 percent for Investor Owned Utilities.) Based on the expected load and generation capacity, the calculated reserve margin for the 2009 summer is 22.0 percent. This year's calculated reserve margin is 1.4 percent higher than last year's calculation for the summer of 2008 primarily related to the reduction in the load forecast.

The expected reserve margin for this summer includes a total of 2,377 MW import from the Southeastern subregion of SERC to FRCC. The total import into the FRCC Region consists of 825 MW of generation residing in the Southeastern subregion of SERC owned by FRCC entities and the remaining 1,552 MW are firm purchases. These imports account for 5.2 percent of the total reserve margin, and have firm transmission service to ensure deliverability into the FRCC Region. During 2008 summer a total of 2,448 MW (firm transmission service) of external resources were included in the reserve margin calculation for the Region. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts (as available) in place between SERC and FRCC entities.

The 15 percent reserve margin was established based on a Loss Of Load Probability (LOLP) analysis that incorporated system generating unit information to determine the probability that existing and planned resource additions will not be sufficient to serve forecasted loads. The objective of this study is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1 day in a given year is not exceeded. The results of the most recent LOLP analysis indicated that for the "most likely" and extreme scenarios (e. g., extreme seasonal demands; no availability of firm and non-firm imports into the Region; and the non-availability of load control programs), the peninsular Florida electric system maintains a LOLP well below the criterion.

Demand Response is considered as a demand reduction. Each entity within FRCC ensures reliable operation of its Demand Response programs by conducting periodic testing and maintenance.

Currently there is no Renewable Portfolio Standards in Florida. However, a draft rule has been submitted by the Florida Public Service Commission staff to the Florida Legislature for consideration.[55] The amount of variable resources within the FRCC Region is so small that these resources have an insignificant impact on resource adequacy assessments. Within the FRCC Region, variable resources are typically treated as energy-only. However, some entities may use a coincident factor for variable resources in performing resource adequacy assessments. Currently no changes to planning approaches are needed to ensure reliable integration and operation of variable resources within the FRCC Region primarily due to the small amount of expected future variable resources.

The FRCC Region expects to retire a total generation of 52 MW prior to 2009 summer without any anticipated impact on reliability.

The FRCC Region does not have an official definition for deliverability. However, the FRCC Transmission Working Group (composed of transmission planners from FRCC member utilities) conducts regional studies to ensure that all dedicated firm resources are deliverable to loads

[55] http://dms.myflorida.com/content/download/54597/229343/file/02.23.2009

under forecast conditions and other various probable scenarios to ensure the robustness of the bulk power system. In addition, the FRCC Transmission Working Group evaluates planned generator additions to ensure the proposed interconnection and integration is acceptable to maintain the reliability for the bulk power system within the FRCC Region.

Availability and deliverability of internal and external resources are ensured by firm transmission service, purchase power contracts and transmission assessments. These internal and external resources were included in the "2009 Summer Transmission Assessment" demonstrating the deliverability of these resources.

For the 2009 summer period, we do not anticipate any load serving concerns due to fuel supply vulnerabilities. For extreme weather conditions such as hurricanes affecting natural gas supply points, extreme temperatures or impacts to pipeline infrastructure, alternate short-term fuel supply availability continues to be adequate for the Region. There are no additional fuel availability or supply issues identified at this time and existing mitigation strategies continue to be refined. Based on recent studies, current fuel diversity, alternate fuel capability and fuel study results, FRCC does not anticipate any fuel transportation issues affecting resource capability during peak periods or extreme weather conditions this summer.

The FRCC Region is planned and operated such that NERC Reliability Standards are met without the need to identify any specific criteria for minimum dynamic reactive reserve requirements or transient voltage-dip criteria. Transient stability studies are performed by FRCC and no issues have been identified that would impact the 2009 summer season. Small signal analysis is performed when damping issues are identified during transient stability studies. Voltage stability studies performed in the Region involve identifying the worst-case conditions such as the unavailability of multiple units. These studies are normally load-flow based using an algorithm that can identify voltage limitations.

Operational planning assessments performed by FRCC address the requirements of the Transmission Planning (TPL) NERC Reliability Standards. The results of these assessments demonstrate that operator intervention can successfully mitigate reliability issues that may arise during the summer of 2009.

Under firm transactions, reactive power-limited areas can be identified during transmission assessments performed by the FRCC. These reactive power-limited areas are typically localized pockets that do not affect the bulk power system. The FRCC 2009 Summer Transmission Assessment did not identify any reactive power-limited areas that would impact the bulk power system during the summer of 2009 season. The FRCC Region has not identified the need to develop specific criteria to establish a voltage stability margin.

Given the FRCC fuel diversity as listed within the FRCC Load and Resource Database, it is anticipated that fuel supply availability will be adequate during summer peak conditions. For potential generating capacity constraints due to fuel delivery problems, the FRCC State Capacity Emergency Coordinator (SCEC) along with the Reliability Coordinator (RC) have been provided with an enhanced ability to assess Regional fuel supply status by initiating Fuel Data Status reporting by Regional utilities. The recently revised FRCC Generating Capacity Shortage Plan includes specific actions to address capacity constraints due to generating fuel shortages. This process relies on utilities to report their actual and projected fuel availability along with alternate fuel capabilities to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output depending on the event initiating the reporting process. Data is aggregated at FRCC and is provided, from a Regional perspective, to the RC, SCEC, and governing agencies as requested. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and is quickly integrated into an enhanced Regional Daily Capacity Assessment Process along with various other coordination protocols to ensure accurate reliability assessments of the Region and also ensure optimal coordination to minimize impacts of Regional fuel supply issues and disruptions.

Although FRCC has reviewed various types of fuel supply issues in the past, the increased reliance of generating capacity on natural gas has caused FRCC to address this fuel type specifically. FRCC continues coordination efforts among natural gas suppliers and generators within the Region. The recently revised FRCC Generating Capacity Shortage Plan[56] includes specific actions to address capacity constraints due to natural gas availability constraints and includes close coordination with the pipeline operators serving the Region. The FRCC Operating Committee has also developed the procedure, *FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers*[57], to enhance the existing coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators and in response to FERC Order 698.

The FRCC Region is currently experiencing drought conditions. However, these drought conditions are not expected to impact generation capacity. The FRCC Region does not rely on hydro generation, therefore hydro conditions and reservoir levels will not impact the ability to meet the peak demand and the daily energy demand.

An interregional transfer study is performed annually to evaluate the total transfer capability between FRCC and the Southeastern subregion of SERC. Joint studies of the Florida/Southeastern transmission interface indicate a summer seasonal import capability of 3,600 MW into the Region, and an export capability of 1,000 MW. These joint studies account for constraints within the FRCC and the Southeastern subregion of SERC.

The FRCC ensures resource adequacy by maintaining a minimum 15 percent reserve margin to account for higher than expected peak demand due to weather or other conditions. In addition, there are operational measures available to reduce the peak demand such as the use of Interruptible/Curtailable load, DSM (HVAC, Water Heater, Pool Pump, etc.), Voltage Reduction, customer stand-by generation, emergency contracts, and unit emergency capability.

[56] https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FINAL%20FRCC%20Generating%20Capacity%20Shortage%20Plan.pdf

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

Load serving projects can be delayed, deferred, or cancelled in response to the latest load forecasts. In-services dates of significant projects for this summer are not expected to be impacted by the latest load forecasts. These load forecasts have been reduced to reflect the anticipated economic conditions throughout the FRCC Region for the upcoming summer. However, there are no expected impacts on reliability for the summer of 2009 due to the degraded economic conditions within the Region.

FRCC is not anticipating any other reliability concerns for the 2009 summer conditions. Unexpected potential reliability real-time issues identified by the Reliability Coordinator can be resolved with existing operational procedures.

Region Description

FRCC's membership includes 26 Regional Entity Division members and 25 Member Services Division members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. The Region has been divided into 11 Balancing Authorities. As part of the transition to the ERO, FRCC has registered 76 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The Region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC website (https://www.frcc.com/default.aspx).

MRO

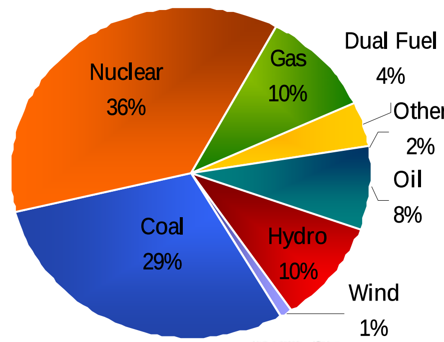
Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	49,921
Direct Control Load Management	1,421
Contractually Interruptible (Curtailable)	1,750
Critical Peak-Pricing with Control	0
Load as a Capacity Resource	0
Net Internal Demand	46,750

2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	48,047	-2.7%
2008 Summer Actual Peak Demand	45,171	3.5%
All-Time Summer Peak Demand	47,629	-1.8%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	56,388	20.6%
Deliverable Capacity Resources	58,505	25.1%
Prospective Capacity Resources	58,527	25.2%
NERC Reference Margin Level	-	15.0%

On-Peak Capacity by Fuel Type



Introduction

The forecast for 2009 summer peak demand is slightly lower than that for 2008 summer because of the nationwide economic downturn. Since 2008 summer, significant wind generation has been added, and one large coal plant has come on line since. The combination of reduced demand and increased generation results in the forecast reserve margin to increase above the 2008 summer level and is well above target levels within the MRO Region.

Within the MRO Region, the Upper Midwest area is rich in wind resource, of which capacity factors may reach the 40–45 percent range. Four states within the MRO Region have Renewable Portfolio Standards, which require a percentage of annual energy to be served by renewable resources by a specified year. Two additional states have renewable portfolio objectives, which are similar to RPS although not mandates. Wind generation levels are expected to reach nearly 6,000 MW (nameplate) this summer for the MRO Region, which is a 50 percent increase since 2008 summer. The majority of this wind generation is located in the MRO- U.S. footprint. At times, a large percentage of the wind generation simultaneously operates during low demand periods. Most of the installed wind farms are energy-only resources and have operating guides and Special Protection Systems associated with them. Managing the magnitude and variability of wind generation this summer will be an increased challenge for the Midwest ISO Reliability Coordinator and its associated Transmission Operators.

Other than the challenge of operating a large amount of wind generation, there are no reliability concerns anticipated within the MRO Region for 2009 summer.

MRO's members and Registered Entities are affiliated with six Planning Authorities: the Midwest ISO, MAPP, American Transmission Company, Manitoba Hydro, SPP, and SaskPower. Three Reliability Coordinators are registered with the MRO: Midwest ISO, SPP and SaskPower. Several of the MRO members are Midwest ISO tariff members and therefore participate in the Midwest ISO market operations. The Midwest ISO also spans into the RFC and SERC Regions. The Midwest ISO has recently begun operating as a single Balancing Authority (BA) to facilitate their Ancillary Services Market (ASM). Several MRO members are MAPP tariff members. As of April 1, 2009, the SPP RTO acquired three new tariff and RC members; Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System. The future Regional Entity of the Nebraska entities is still to be determined at this time, so MRO will continue to perform Reliability Assessments for these entities until a decision on NERC Delegation Agreements are made.

Demand

The MRO's forecasted 2009 Summer Non-Coincident Peak Total Internal Demand in the combined MRO–U.S. and MRO-Canada is 49,921 MW, assuming normal weather conditions. This forecast is 2.5 percent below last summer's forecasted total demand of 51,166 MW. The MRO 2009 forecast Net Internal Demand is 46,750 MW, which is 2.8 percent lower than the 2008 forecasted Net Internal Demand of 48,047 MW. The recession and nation-wide economic downturn are the main reasons for the slight decline in forecast.

Last summer's actual peak demand was 45,171 MW. This actual peak value is not adjusted to exclude any additional Interruptible Demand and DSM that may not have been implemented. This actual peak for 2008 is about 5 percent lower than the all-time peak of 47,629 MW (2007). Moderate weather and the economic downturn are likely reasons for the reduction in actual peak.

MRO staff distributed the NERC 2009 summer data request spreadsheet to the applicable entities within the MRO as it was received from NERC. The members fill out these workbooks and MRO staff compiles them to obtain an MRO Regional total value. MRO staff emphasizes to the data request recipients that each MW of demand must be counted once and only once and that they should carefully coordinate with their neighbors as necessary. Although individual recipients often submit coincident demand for their system, the overall results reflect a non-simultaneous demand total for the MRO Region.

Interruptible Demand (1,750 MW, 3.5 percent) and Demand Side Management DSM (1,421 MW, 2.9 percent) programs, amounting to 6.4 percent of the MRO's Forecasted Total Internal Peak Demand of 49,783 MW are used by a number of MRO members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the summer season.

Peak demand uncertainty and variability due to extreme weather or other conditions are accounted for within the determination of adequate generation reserve margin levels. Both the MAPP Generation Reserve Sharing Pool (GRSP) members and the former MAIN members within MRO[58] use a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss

[58] The former MAIN members are Alliant Energy, Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric.

of Load Expectation (LOLE) or the percentage reserve margin necessary to obtain a LOLE of 0.1 day per year or one-day-in-ten years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions.

Each MRO member uses its own forecasting method, meaning some may use a 50/50 forecast and some may use a 90/10 forecast. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. From a Regional perspective, other than economic factors, there were no significant changes in this year's forecast assumptions in comparison to last year.

Forecasts are developed for the Saskatchewan system to cover possible ranges in economic variations and other uncertainties such as weather. Forecasts are developed for the Saskatchewan system using a Monte Carlo simulation model to reflect economic and weather uncertainties. This model considers each variable to be independent from other variables and assumes the distribution curve of a probability of occurrence of a given result to be normal. Results are based on an 80 percent confidence interval. This means that a probability of 80 percent is attached to the likelihood of the load falling within the bounds created by the high and low forecasts.

Generation

The existing internal Exisiting-Certain resources for the MRO–U.S. and MRO-Canada 2009 summer are 58,014 MW. The existing internal Existing-Other resources for the MRO–U.S. and MRO-Canada 2009 summer are 4,942 MW (due to derates, maintenance, transmission limitations). Planned resources that will be in service this summer are 2,117 MW. Only planned resources with an expected service date of June 1, 2009 or sooner were included. These values do not include firm or non-firm purchases and sales. The month of July was used in all cases to be consistent.

The variable resources for the MRO-U.S. (wind generation) expected to be available at peak times is 1,130 MW, based on 20 percent of nameplate capacity of 5,924 MW. For wind generation, nameplate capability is assumed as maximum capability, although simultaneous output of geographically disperse wind farms at 100 percent nameplate capability is highly unlikely. 20 percent of nameplate capacity is used by the Midwest ISO when determining capacity of variable generation. 20 percent is also assumed available at peak load by the MRO Model Building Subcommittee when building peak models. Historically, the Midwest ISO has recorded a maximum output of about 65 percent of wind nameplate capacity operating simultaneously throughout the Region during peak demand. The Midwest ISO has also recorded approximately 2 percent of wind nameplate capacity operating simultaneously throughout the Region during peak demand. Saskatchewan, which has about 172 MW of nameplate wind, and Manitoba Hydro, which has about 100 MW of nameplate wind, do not count wind resources for reliability/capacity purposes.

The biomass portion of resources for the MRO expected to be available at peak times is 331 MW.

No Future or Conceptual capacity resources have been used for reliability analysis or reserve margin calculations in this assessment.

Capacity Transactions on Peak

For the 2009 summer season, the MRO is projecting total firm purchases of 1,450 MW. These purchases are from sources external to the MRO Region. The MRO has approximately 1,009 MW of total projected sales to load outside of the MRO Region. The net import/export of the MRO Region can vary at peak load, depending on system conditions and economic conditions.

Firm purchases from MRO-Canada (Saskatchewan and Manitoba) into the MRO–U.S. are limited to 2,415 MW due to the operating security limits of the two interfaces between these two provinces and the U.S. For the 2009 summer, 1423 MW of firm exports from MRO-Canada to MRO-U.S. are expected. 50 MW of this export will originate from Saskatchewan.

Throughout the MRO Region, firm transmission service is required for all generation resources that are used to provide firm capacity; also meaning that these firm generation resources are fully deliverable to the load. MRO expects the various reserve margin targets will be met without needing to include energy-only, uncertain, or transmission-limited resources.

MRO members include firm capacity purchases from outside of the Region in reserve margin calculations.

Transmission

Iowa

Significant new transmission facilities that are planned to be in service prior to this summer season include:

- Monona-Victory 161 kV line upgrade. In service in April 2009.
- Sac-Pocahontas 161 kV line re-conductor. In service in April 2009.
- Webster-Hayes 161 kV line upgrade. In service in April 2009.
- Grimes Tap to Bittersweet Road 161 kV. A double-circuit 161 kV line tap will connect the Bittersweet Road Substation to the existing Perry-NE Ankeny 161 kV line. In service in June 2009.
- Salem 345/161 kV transformer upgrade. In service in June 2009.

Nebraska

Phase I of NPPD's Electric Transmission Reliability (ETR) Project for East-Central Nebraska was completed in June 2008. Phase I of the ETR Project entailed conversion of an existing 230 kV transmission line to 345 kV from just north of Norfolk to a point just north of Columbus, expansion of the Hoskins Substation near Norfolk and construction of the new Shell Creek Substation north of Columbus. Completion of this phase of the project is expected to improve local area voltage support.

As a part of the Nebraska City Unit 2 power plant project, a new 345 kV transmission line from the site of the Nebraska City 2 plant to a new substation southeast of Lincoln was energized in July 2008. Nebraska City Unit 2 is expected to be on-line by May of 2009.

A new 345 kV transmission line that completes a north tier segment around the city of Lincoln was energized in 2008. This line is expected to reduce contingent overloading issues on critical assets in the Lincoln area, which in turn, will reduce the need for temporary operating guides on these facilities.

Northern MRO

Several new wind farms have been installed in North Dakota this past year including the Langdon 2 generating project, with a nameplate capacity of 40 MW. This brings the Langdon Wind generation total to 200 MW. An associated action was the up-rate of the Hensel-Drayton 115 kV line to support the Langdon Wind operation during summer off-peak conditions during a prior outage of the Langdon-Devils Lake 115 kV line.

Pillsbury Wind was brought on line, with a present nameplate capacity of 197 MW. A new generator lead line (230 kV) from Pillsbury to Maple River was put in service as part of the project. Pillsbury Wind is approved for up to 358 MW delivered to the Maple River substation. The remainder of the project is scheduled to come on line in either the 3rd or 4th quarter of 2009. New peaking generation will also be commissioned in Minnesota this spring/early summer. A 170 MW unit will be connected to the Elk River Station 230 kV bus.

Several transmission additions have been completed in the Northern MRO Region. The conversion of the Canby to Appleton line from 41.6 kV to 115 kV has been completed. The Split Rock to Nobles 345 kV line was recently energized which completed all the transmission improvements for the 825 MW of firm capacity for the wind generation in southwestern Minnesota (Buffalo Ridge area.)

Facility additions needed to accommodate the 130 MW increase in the North Dakota Export Stability Interface (NDEX) from 1,950 MW to 2,080 MW are expected to be in service this coming summer which include capacitor additions and up-ratings of facilities. Operating guide(s) will be implemented if necessary for any facilities that may become affected if load grows faster than predicted.

Wisconsin-Upper Michigan Systems (WUMS)

Significant transmission additions with expected in-service dates between January 2009 and June 2009 are listed in the following. There are no concerns in meeting the targeted in-service dates of these projects.

- Rebuild/convert Conover-Plains 69 kV line to 138 kV. Twin Lakes-Iron Grove portion expected to be in-service in April 2009. The entire project is expected to be in-service in June 2010.
- Rock River-Elkhorn 69 to 138 kV line rebuild/voltage conversion project. Expected to be in-service in April 2009.

- Construct a new North Madison-Huiskamp 138 kV line. Expected to be in-service in May 2009.
- Construct Gardner Park-Highway 22 345 kV line. Expected to be in-service in June 2009.
- Construct Werner West-Highway 22 345 kV line. Expected to be in-service in June 2009.
- Add a new Oak Creek 345/138 kV Transformer #2. Expected to be in-service in June 2009.

Operational Issues

There are no known unit outages that would impact reliability during this summer season. Operating studies have been or will be performed for all scheduled transmission or generation outages. When necessary, temporary operating guides will be developed for managing the scheduled outages to ensure transmission reliability.

There are no known environmental or regulatory restrictions that could impact reliability during the 2009 summer season.

Water levels in the MRO-U.S. and MRO-Canada are adequate to meet reserve margin needs. However, from an energy perspective, reservoir water levels throughout the northern MRO-U.S. Region (Montana, North Dakota, and South Dakota) have improved in recent years, but continue to remain below normal. Hydro unit limitations continue for this summer due to requirements for endangered species. These issues coupled with maintenance and other operating issues will likely continue to reduce the magnitude and duration of power transfers (on an energy basis) out of northern MRO. The Manitoba and Saskatchewan water conditions are expected to be normal for summer and likely above average in the spring.

The MRO Region is not experiencing a drought that would limit thermal unit cooling.

Midwest ISO members within the MRO participated in the Midwest ISO 2008/2009 winter assessment study and are also participating in the 2009 summer assessment study that will be initiated soon by the Midwest ISO. The subregional groups under the MAPP Transmission Operations Subcommittee prepare an assessment of expected summer conditions and also update (or create new) operating guides to accommodate expected summer conditions. The objectives of these studies are to provide system operators with guidance as to possible system conditions that would warrant close observation to ensure system security.

Saskatchewan performs N-1 and N-1-1 operational planning studies as part of developing the Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability, and on-going operating guides to address planned and forced equipment outages. Studies consider simultaneous transfers to Manitoba and North Dakota; and any known transmission and generation issues. The Manitoba-Saskatchewan operating guideline defines secure transfer capabilities and operational requirements for the season. It identifies maximum Manitoba-Saskatchewan West flow and East flow transfer capability, and provides an operating guideline for the season. The guideline qualifies key parameters in the Manitoba-Saskatchewan network which affect inter-utility transfers, and provides the present transfer capabilities as the initial basis for future system developments and studies.

Significant increases in wind generation have occurred within the MRO-U.S. Region. Approximately 4,000 MW of nameplate wind generation existed on June 1, 2008. This will increase to about 6,000 MW of nameplate by June 1, 2009, a 50 percent increase in one year. Although certain wind generation can provide counter-flows in normally congested areas, more often there are challenges for the Midwest ISO Reliability Coordinator to manage this variable generation because much of it is being added as an Energy Resource and using available transmission capacity on a non-firm basis. Typically, transmission is constructed to accommodate conventional generation capacity that can be dispatched and that capacity usually comes on line after the transmission upgrades are made. Many owners of the wind generation are also financing upgrades to the transmission system, however, the generation usually is built first, and the transmission may follow months or years later. Oftentimes a Special Protection System (SPS) is installed to automatically mitigate overloads. These SPSs usually present operating challenges to the Midwest ISO Reliability Coordinator and the system operators in the Region. Operating guides are, however, developed and implemented for those situations.

It has been observed that the rapid increase or decrease of, or the overall high or low levels of wind generation in Iowa and Minnesota can have significant impact on the flows through the WUMS western and southern interfaces, namely MWEX and SOUTH TIE interfaces, respectively. ATCLLC and the Midwest ISO are monitoring this operational issue closely. An operational study performed hourly by the Midwest ISO anticipates the impacts of the sudden change in wind generation in Iowa and Minnesota on a number of selected Flowgates. Operators will be alerted when the study results show the loading of any monitored Flowgate comes within 95 percent of its rating. ATCLLC also analyzes the data and trends related to this operational issue monthly to be better prepared for managing the potentially impacted Flowgates, particularly the MWEX and SOUTH TIE interfaces, looking forward.

Wind generation will need to be integrated into congestion management processes in an automated fashion. Accurate forecasting of individual wind farms and the ability to accurately determine system impacts of individual wind farms will help Reliability Coordinators achieve this. Variable generation will also need to be managed according to the firmness of its transmission rights along with all other generation. Variable generation will ultimately need to participate day-ahead in organized markets and participate in market dispatch instructions to the extent possible. Management systems for wind farms can initiate rapid runback of generation. This aspect of controllability will likely be used by Reliability Coordinators and organized markets to efficiently and fairly manage wind generation during times of congestion.

The MAPP-MISO Seams Operating Agreement expired on March 31, 2009. The Midwest ISO has individual service agreements with MAPP members for Module F Part II service effective April 1, 2009.

Iowa

A predominant flow pattern that was observed during summer operations in Iowa during the period 2000–2007, characterized by heavy East to West power transfers across the state, is expected to be less of an impact during 2009 summer. The primary reasons for this change are the additions of the Nebraska City Unit 2 in eastern Nebraska and several wind farms in Central and Western Iowa. With an increase in the rating of the COOPER_S Flowgate from its interim limit to its ultimate rating, a new 161 kV flowgate in South-West Iowa was developed in June 2008 and incorporated into the MAPP, Midwest ISO, and SPP transmission evaluation processes. The South to North system bias observed in summer 2007 could return causing TLR calls and implementation of the MISO congestion management procedures, especially during prior outage conditions.

The addition of wind generation will present new challenges to transmission operators and reliability coordinators. This new generation includes Farmers City wind farm, Adair wind farm, Crystal Lake wind farm, Story County wind farm, Iowa Lakes wind farm, Endeavor wind farm, Pioneer Prairie wind farm, and an addition to the existing Pomeroy wind farm. Operating studies indicated that the transmission system is well designed to withstand any single contingency during system intact conditions. However, some prior outage conditions typically require establishing limits on wind farm output or quick reduction of wind generation. Transmission Operators will also closely monitor underlying 69 kV facilities and reduce wind farm generation in cases of overloading the 69 kV facilities. Operating guides exist for all of these wind farms, so transmission operators will have clear guidance for a number of operating scenarios during which control actions on wind farm output needs to be implemented.

Managing established flowgates will be helpful in preventing the occurrence of heavy power transfers that may cause post-contingency overloading of transmission system facilities. One of the most limiting flowgates during summer operating regimes in North/Central Iowa will be partially re-conductored in 2009. The standing operating guides for all Iowa Flowgates have been reviewed and are available to transmission operators. These standing operating guides, and temporary operating guides that will be issued in cases of scheduled or forced outages, have proven to be effective in addressing operational issues associated with summer peak system conditions as well as other system conditions.

Overall, the Iowa system is expected to operate in a reliable manner during 2009 summer by meeting the requirements of NERC Reliability Standards.

Nebraska

As of April 1, 2009, the Nebraska companies began operating under the purview of the SPP Reliability Coordinator.

No significant operational concerns are expected in Nebraska during 2009 summer. Where large transfers might occur, operating guides and operating procedures have been put in to place to maintain the reliable operation of the Nebraska regional transmission system.

Operational studies have been performed and will be updated as necessary for scheduled transmission and generation outages during summer peak and summer off-peak loading periods. Temporary operating guides will be issued for those outages which require actions or limitations to protect system operating limits.

Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) currently post six constrained paths, which are located within or adjacent to the NPPD and OPPD control areas. All of these flowgates have approved operating guides that have historically proven effective in dealing with system conditions throughout the year.

During the summer peak and off-peak loading periods the Cooper South Flowgate (COOPER_S) and the Western Nebraska to Western Kansas Flowgate (WNE_WKS) are monitored closely. Upgrades to the COOPER_S Flowgate were completed in 2008 resulting in a flowgate rating increase which was implemented in February of 2009. It is anticipated that this flowgate rating increase will result in less frequent TLR events during the summer peak and summer off-peak loading periods. During peak loading periods with heavy exports to the south, NERC TLR is expected to be implemented to limit the flows on the Gerald Gentleman Station-Red Willow 345 kV line to address system operating limits associated with the WNE_WKS Flowgate.

With increased loads in the western Nebraska region during the summer months, stability limitations associated with the Gerald Gentleman Station Stability Flowgate are less severe. High power transfers out of the western Nebraska region are typically less during the summer months than in winter months.

In the past several years, there has been a large increase in the number of days when the dc ties are transferring power from east-to-west, which reduces the west-to-east flows that are normally seen across Nebraska. It is anticipated that this pattern of the dc ties flowing in the east-to-west direction will continue this summer.

Northern MRO

No significant operational issues are expected this summer for the northern MAPP region. The existing operating guides and temporary operating guides that are developed as needed, have maintained reliable system conditions throughout the year.

A number of bulk transmission outages are scheduled in the northern MRO Region for construction and maintenance; however, no operating problems are expected. Temporary operating guides will be developed as necessary. Standing operating guides are being reviewed and will be in place for the 2009 summer.

Wisconsin-Upper Michigan Systems (WUMS)

The Minnesota Wisconsin Export (MWEX) interface is comprised of Arrowhead-Stone Lake 345 kV line and King-Eau Claire 345 kV line. The west to east transfer through the MWEX interface is constrained due to potential transient voltage recovery violation and voltage instability. The MWEX interface is managed as a reciprocal Interconnection Reliability Operating Limit (IROL) Flowgate of Midwest ISO and MAPP. An operating guide is in place that defines MWEX limits under system intact and various N-1 prior outage conditions. An operational planning study is underway that evaluates the impact on the MWEX interface under the conditions of high and low levels of wind generation west of the WUMS footprint.

The WUMS southern interface includes tie lines in the southwest and southeast interfaces. The southwest interface comprises the Wempletown-Paddock 345 kV line and Wempletown-

Rockdale 345 kV line. The southeast interface comprises Zion-Arcadian 345 kV line, Zion-Pleasant Prairie 345 kV line, and Zion-Lakeview 138 kV line. The WUMS southern interface is thermally limited for critical N-1 contingencies and voltage stability limited for critical N-2 contingencies during periods of heavy imports through the interface. An operating guide is in place that helps to manage these constraints.

The eastern portion of the Upper Peninsula of Michigan (UP) experiences flows in both west to east and east to west directions. Heavy flows in either direction can cause potential thermal and voltage violations in the eastern UP. These constraints are managed by opening the 69 kV lines between the eastern UP and the rest of the WUMS system, using procedures defined in an operating guide.

Reliability Assessment Analysis

The MRO Reliability Assessment Committee is responsible for the seasonal assessments. The MRO Transmission Assessment Subcommittee, MRO Resource Assessment Subcommittee, the MAPP Transmission Operations Subcommittee, the ATCLLC, and Saskatchewan Power Corporation all contribute to this MRO seasonal Reliability Assessment. To prepare this MRO Regional self-assessment, MRO staff sent the NERC spreadsheets to the Registered Entities within MRO and collected the individual entity's load forecast, generation, and demand-side management data. The staff then combined the individual inputs from these spreadsheets to calculate the MRO Regional totals. The staff also sought responses to the questions included in the NERC seasonal request letter, from Planning Authorities within the MRO Region — MAPP, ATCLLC, and SaskPower. The MAPP Transmission Operations Subcommittee provided detail from the various MAPP operating groups. Using the information gathered from this process, the MRO Resource Assessment Subcommittee prepared the resource assessment portions, while the Transmission Assessment Subcommittee prepared the transmission assessment and operational issues portions. Finally, the MRO Reliability Assessment Committee, which is ultimately responsible for the long-term reliability assessments, reviewed and approved the final draft before it was submitted to NERC.

The MRO's projected 2009 Summer reserve margin is 25 percent without Existing, Other resources.

For the MAPP GRSP, which includes all MRO members except the former MAIN members and Saskatchewan, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP requires a 15 percent reserve margin for predominantly thermal systems, and 10 percent reserve margins for predominantly hydro systems, based on previously conducted LOLE studies. Approximately 8,850 MW of generation in the MAPP GRSP (15.7 percent of MRO net internal capacity) is associated with predominantly hydro systems and only requires a 10 percent reserve margin. The projected MRO reserve margin of 25 percent for the 2009 summer season is in excess of the target reserve margin.

The former MAIN members now within MRO do not belong to the MAPP GRSP. Generation resource adequacy for the former MAIN members is assessed based on LOLE studies previously conducted by the MAIN Region. Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum short-term planning reserve margin of 14 percent. The

Midwest ISO has conducted a Loss of Load study establishing a 12.7 percent reserve margin requirement for all Midwest ISO load serving entities. In addition, the Midwest ISO began operation of its Ancillary Services Market (ASM) on January 6, 2009, which included operation as a single Balancing Authority. More information is available at:

http://www.midwestmarket.org/publish/Folder/469a41_10a26fa6c1e_-741b0a48324a.

The projected MRO reserve margin of 25 percent for the 2009 summer season is in excess of the various target reserve margins within the Region.

Saskatchewan's reliability criterion is based on annual expected unserved energy (EUE) analysis and equates to an approximate 15 percent reserve margin requirement. Since Saskatchewan is self-reliant on capacity, (i.e., it does not rely on resources external to their province for capacity) Saskatchewan's forecasted reserve margin of 15 percent for the 2009 summer season meets its target reserve margin.

Only firm purchases/sales from/to the external Regions were used in margin calculations in 2008 and 2009. This year's import of 1,450 MW compares closely with last year's import of 1,192 MW, and this year's export of 1,009 MW compares closely with last year's export 836 MW. This results in a net import of 441 MW as compared to last year's import of 356 MW.

Saskatchewan did not rely on outside resources for 2008 summer and is not relying on outside resources for 2009 summer. It plans to self-supply all planning and operating reserves for the 2009 summer season.

Transmission Reliability Margins (TRM) are calculated and reserved by the Transmission Providers within the MRO Region to assure that operating reserves can adequately be delivered. These operating reserves can include resources outside of the MRO Region since most MRO members participate in the Midwest Contingency Reserve Sharing Group.

This summer's projected reserve margin of 25 percent, which includes certain resources only and net interchange, can be compared with last summer's projected reserve margin of 17.5 percent. A portion of this increase in reserve margin is due to the reduction in demand forecast. The remainder is due to the increase in generation capacity (approximately 4,000 MW).

The projected reserve margin for Saskatchewan alone for 2009 summer is approximately 15 percent. This compares to 19 percent for 2008 summer. This decrease in reserve margin is due to significant load growth within the province of Saskatchewan.

Interruptible demand and DSM reductions are removed before reserve margins are calculated. The other Demand Response categories (reductions through real-time pricing and load as a capacity resource) are not used within the MRO Region.

Saskatchewan assumes that all of its load will be served according to the load forecast.

Renewable Portfolio Standards, as provided on the U.S. Department of Energy website[59] (excludes Canadian provinces) are as follows:

Table MRO - 1: Renewable Portfolio Standards		
State/Province:	Amount (% Energy);	Year:
MN*	25%	2025
IA*	105 MW	- -
MT*	15%	2015
WI*	10%	2015
ND, SD (Objective)	10%	2015
NE*	None	
Manitoba	None	
Saskatchewan	None	

The reliability impact of generator interconnection in the Midwest ISO foot print is evaluated by Midwest ISO members in coordination with the Midwest ISO and the interconnecting customers through the Midwest ISO generator interconnection queue process. The interconnecting wind farms are required to have low voltage ride-through and reactive power capabilities as specified in the 2005 FERC Order 661-A. These requirements have positive impact on reliability.

Wind farm modeling and assumptions used in operational planning studies have been evolving, which has helped achieve better study efficiency and results that are more accurate. However, further improvement is necessary, particularly in light of increasing wind penetration levels in MRO footprint. Issues include wind farm reactive capability modeling, assumptions of real power dispatch levels under peak and other load conditions, capacity credit assumption for wind farms in resource adequacy study, etc.

The reliability impact due to retirement of generating units in the Midwest ISO footprint is evaluated by Midwest ISO and affected entities. The Midwest ISO study procedure for generation retirement can be found in the MISO Planning Business Practice Manual through the following link: http://oasis.midwestiso.org/OASIS/MISO.

Under the Midwest ISO procedure, if the potential retirement of a unit causes reliability concerns that could not be addressed by feasible alternatives, such as generation re-dispatch, system re-configuration, transmission reinforcement acceleration, etc., then the unit will be required to operate under a System Supply Resource (SSR) agreement with the Midwest ISO until such alternatives become available. There are no known unit retirements that will impact reliability for this summer.

[59] http://www.eia.doe.gov/oiaf/analysispaper/rps/pdf/tbl1.pdf

Generation deliverability studies are performed by Transmission Providers within the MRO Region. Links to deliverability criteria within the MRO Region are:

http://www.midwestiso.org/page/Generator+Interconnection
http://www.mappcor.org/content/policies.shtml
https://www.oatioasis.com/spc/

Throughout the MRO Region, firm transmission service is required for all generation resources that are used to provide firm capacity; also meaning that these firm generation resources are fully deliverable to the load. The MRO expects to meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

There are no known deliverability concerns with the various methods used within the MRO Region for firm deliverability.

To be counted as firm capacity the MAPP GRSP, former MAIN utilities, and Saskatchewan require external purchases to have a firm contract and firm transmission service. For resources internal to the footprint, the deliverability is governed by the interconnection agreements between Transmission Providers. Therefore, MRO entities do not consider it necessary to repeat these same analyses.

The MRO considers known and anticipated fuel supply or delivery issues in its assessment. Because the MRO has a large diversity in fuel supply, inventory management, and delivery methods throughout the Region, it does not have a specific mitigation procedure in place should fuel delivery problems occur. MRO and its members closely monitor the delivery of Powder River Basin coal to ensure adequate supply. MRO does not foresee any other significant fuel supply or fuel delivery issues for the upcoming 2009 summer season. Therefore, there should be no apparent impacts to the reliability of meeting peak electrical demand for the 2009 summer season.

Fuel-supply interruption in Saskatchewan is generally not considered an issue for the following reasons:

- Coal resources have firm contracts, are mine mouth, and stock is also maintained in the event that mine operations are unable to meet the required demand of the generating facility.
- Saskatchewan has 20 days of on-site stockpile for each of its coal facilities. Strip coal reserves are also available and only need to be loaded and hauled from the mine.
- Natural gas resources have firm transportation contracts with large natural gas storage facilities located with the province backing those contracts up.
- Hydro facilities/reservoirs are fully controlled by Saskatchewan.

Policies or practices for fuel supplies vary within the MRO Region. Specific practices are determined by the individual member companies and a Region-wide policy for fuel supplies and on-site inventory does not exist. However, inherent within the obligation to serve load is that adequate fuel supplies exist.

The following discussion is based on the MRO/RFC/SPP/SERC-W 2009 Summer Inter-regional Assessment (Reference 4). Non- simultaneous Total Import Capabilities into MRO from RFC-W, SERC-W, and SPP Regions:

Table MRO - 2: 2009 Summer Inter-regional Assessment	
Transfer Direction	**TIC (MW)**
RFC_W-MRO	28
SPP-MRO	2,800
SERCW-MRO	0

The Total Import Capability (TIC) is equal to the net import into MRO (700 MW) in the base case plus the First Contingency Incremental Transfer Capability (FCITC) obtained in the transfer analysis. These studies recognize constraints internal and external to MRO.

Transient, voltage and small signal stability studies are performed as part of the near-term/long-term transmission assessments (References 1, 6, 7, 8). Voltage stability is also evaluated in the Midwest ISO's seasonal assessments (Reference 2, 3). The results of the Midwest ISO summer assessment were not available prior to the due date of this regional assessment. No transient, voltage, or small signal stability issues are expected that impact reliability during the 2009 summer season.

Saskatchewan does not expect any small signal stability problems due to system design practices. The majority of the units in Saskatchewan have power system stabilizers and have been tuned to provide damping for local and inter-area modes.

Most subregional entities evaluate dynamic reactive reserve requirements on a case-by-case basis if issues are identified. For example, dynamic reactive margin is part of the ATCLLC Planning Criteria, which is determined using a reduction to the reported reactive capability of synchronous machines. A 10 percent dynamic reactive margin is required in the intact system and a 5 percent dynamic reactive margin is required under NERC Category B contingencies.[60] Manitoba Hydro maintains a 150 Mvar reserve on the Dorsey Substation synchronous condensers at all times to cover for the loss of a small and large Synchronous condenser, therefore, preventing voltage collapse from occurring. In addition, no less than 20 Mvar reserve per in-service synchronous machine is permitted when the synchronous machines are taking in Mvar. This is required to

[60] ATCLLC collects the generator maximum reactive capability information from the generator owners within ATCLLC footprint. For reactive reserve analysis, power flow cases would be created with a 5 percent or 10 percent simultaneous reduction in maximum reactive capability of all generators within ATCLLC footprint. Analysis of Category A and B contingencies would then be performed. Voltage violations are not acceptable in the case with a 10 percent reduction in generator maximum reactive capability under Category A contingencies. Voltage violations are not acceptable in the case with a 5 percent reduction in generator maximum reactive capability under Category B contingencies.

reduce the risk of system over-voltage for loss of HVdc generation or loss of a synchronous machine during light load periods.

ATCLLC has transient voltage dip criteria. Voltage recovery is required to be within 70 percent and 120 percent of nominal, immediately following the clearing of a disturbance. Voltage recovery is required to be within 80 percent and 120 percent of nominal between 2 and 20 seconds following the clearance of a disturbance. This criterion is applied in the ATCLLC planning 10-year assessment studies to ensure reliability.

Iowa, Nebraska, and Northern MRO all have transient voltage dip criteria or guidelines with varying requirements. To provide an example, the MAPP default criteria require voltage recovery to be within 70 percent to 120 percent of nominal following the clearing of a disturbance.

Saskatchewan's guideline for post-disturbance transient voltage-dip is 0.7 p.u.

During daily operational studies, ATCLLC and Midwest ISO coordinate on the voltage stability analysis for the MWEX interface. A generic 2 percent margin is reserved between the transfer limit identified in the operational studies and the actual limit used in real time operations.

Voltage stability margin is part of the ATCLLC Planning Criteria. Under NERC Category B contingencies, the steady state system operating point of selected areas for evaluation is required to be at least 10 percent away from the nose of the P-V curve. This criterion is applied for evaluation of selected areas in the ATCLLC planning 10-year assessment studies (Reference 1) to ensure reliability.

Reasons for the delay or cancellation of a proposed generating plant are often unknown and are ultimately a business decision of the potential generation owner. However, it is not expected that the delay/cancellation of these units will impact reliability within the MRO Region due to the large reserve margins expected for this summer.

Other Region-Specific Issues that were not mentioned above

There are no other known reliability concerns anticipated within the MRO Region for 2009 summer.

Region Description

The Midwest Reliability Organization (MRO) has 48 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and/or Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant and Transmission System Operator. The MRO has 116 registered entities. The MRO Region as a whole is a summer peaking Region. The MRO Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is approximately 1,000,000 square miles with an approximate population of 20 million.

MRO Reference Documents

1. 2008 – ATCLLC 10-Year Transmission System Assessment Update, http://www.atc10yearplan.com
2. Midwest ISO Summer 2008 Coordinated Seasonal Transmission Assessment, http://www.midwestiso.org/home
3. Midwest ISO Winter 2008/09 Coordinated Seasonal Transmission Assessment, http://www.midwestiso.org/home
4. Midwest ISO Summer 2009 Coordinated Seasonal Transmission Assessment (ongoing), http://www.midwestiso.org/home
5. Eastern Interconnection Reliability Assessment Group (ERAG) Summer 2009 Inter-regional Transmission Assessment, MRO-RFC-SERC West-SPP (MRSWS) sub-group study (on-going), ftp://compweb4.midwestreliability.org
6. Reliability First Corporation (RFC) Summer 2009 Transmission Assessment Studies (on-going), http://www.maininc.org/
7. 2008 MAPP System Performance Assessment
8. MAPP Small Signal Stability Analysis Project Report, June 2007
9. *http://www.midwestiso.org/page/Expansion%20Planning, Midwest ISO 2007 Expansion Planning*
10. MAPP Members Reliability Criteria and Study Procedures Manual, February, 2009
11. The MAPP Reliability Handbook, December 2004
12. Manitoba Hydro - Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability

NPCC

Regional Assessment Summary

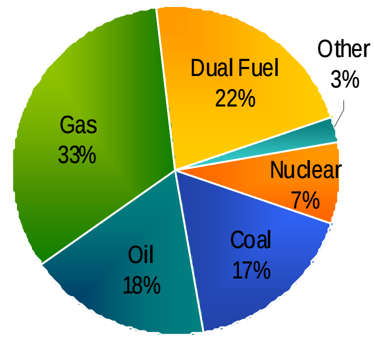
2009 Summer Projected Peak Demand	MW
Total Internal Demand	110,538
Direct Control Load Management	378
Contractually Interruptible (Curtailable)	1,726
Critical Peak-Pricing with Control	0
Load as a Capacity Resource*	2,100
Net Internal Demand	106,334

2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	106,874	-0.5%
2008 Summer Actual Peak Demand	104,340	1.9%
All-Time Summer Peak Demand	114,264	-6.9%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	135,841	27.7%
Deliverable Capacity Resources	140,359	32.0%
Prospective Capacity Resources	141,312	32.9%
NERC Reference Margin Level	-	15.0%

**Note: NPCC has classified 2,936 MW of Demand Response as a supply resource which does not reduce Total Internal Demand.*

On-Peak Capacity by Fuel Type



Introduction

The forecasted coin cident peak dem and for NPCC during the peak w eek is 110,6 45 MW for 2009. The reserve m argins for the NPCC summ er peaking Areas of New York, New England and Ontario have generally increased for m ost summ er months over the corresponding 2008 values. Over 3,200 MW of capacity additions have been made since 2008 summer. In July 2009 TransÉnergie will be c ommissioning the new Ottawa ar ea Outaouais inter connection with Ontario across the Ottawa River. The interco nnection consists of two 625-M W back-to-back HVdc converters in Québec and a double-circuit 230 kV line to Hawthorne substation in Ottawa. In New England, significant im provements to the transmission system have been completed or are in progress. They include:

- The rem aining com ponents of the Middletown-Norwalk phase of the Southwest Connecticut Reliability Projec t have been placed in servi ce, improving the area's near-term and mid-term reliability and infrastructure.
- The NSTAR 345 kV Transmission Reliability Project, which helps to relieve some of the constraints that limit Boston imports, has also been completed.
- The Short-Term Lower SEMA upgrades proj ect is under constr uction and contains several facilities antic ipated to be in serv ice for 2009 sum mer. This project addresses transmission deficiencies in Lower Southeas t Massachusetts and reduced the reliance on local generating unit that are committed to address second-contingency protection for the loss of two major 345 kV lines.

The five NPCC areas, or subregions, are defined by the following footprints:

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

The Maritime Area and the Québec Area are winter peaking systems; Ontario, New York, and New England are summer peaking systems. When compared with projections for the 2008 summer, in the table NPCC-1, the summer peaking systems are generally projecting reserve margins similar to or higher than the reserve margins projected for the 2008 summer:

Table NPCC - 1: Regional Assessment Summary

	June					July				
	2009S Reserve Margin MW	2009S Capacity Margin %	2009S Reserve Margin %	2008S Reserve Margin MW	2008S Reserve Margin %	2009S Reserve Margin MW	2009S Capacity Margin %	2009S Reserve Margin %	2008S Reserve Margin MW	2008S Reserve Margin %
Maritimes	2161.2	41.1%	69.9%	2751.0	90.5%	2382.2	44.0%	78.7%	2557.9	91.5%
New England	9255.0	27.4%	37.7%	8040.0	34.9%	6046.0	17.8%	21.7%	4844.0	18.4%
New York	9459.0	24.2%	31.9%	9114.4	28.4%	9482.0	24.2%	31.9%	9132.4	28.4%
Ontario	3591.0	13.0%	14.9%	4031.0	17.3%	5411.0	17.8%	21.6%	3917.0	16.1%
Québec	10248.0	32.9%	49.1%	8841.0	42.2%	11502.0	35.7%	55.6%	8810.0	41.8%
	August					September				
	2009S Reserve Margin MW	2009S Capacity Margin %	2009S Reserve Margin %	2008S Reserve Margin MW	2008S Reserve Margin %	2009S Reserve Margin MW	2009S Capacity Margin %	2009S Reserve Margin %	2008S Reserve Margin MW	2008S Reserve Margin %
Maritimes	2486.2	45.3%	82.8%	2789.9	94.0%	2219.2	42.4%	73.6%	2792.9	91.4%
New England	6046.0	17.8%	21.7%	4844.0	18.4%	9651.0	30.4%	43.7%	10788.0	53.0%
New York	9460.0	24.2%	31.9%	9129.4	22.1%	3840.0	11.5%	12.9%	4411.4	13.7%
Ontario	6495.0	21.2%	26.8%	4353.0	18.4%	6944.0	31.5%	31.5%	3957.0	18.4%
Québec	9931.0	32.1%	47.3%	8510.0	39.9%	8664.0	29.5%	41.8%	7970.0	37.8%

NPCC Resource Adequacy Assessment

Through numerous studies and reviews, the NPCC Task Force on Coordination of Planning (TFCP) ensures that the proposed resources of each NPCC Area will comply with NPCC Document A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems (http://www.npcc.org/documents/regStandards/Criteria.aspx)." Section 3.0 of Document A-02 defines the criterion for resource adequacy for each Area as follows:

> **Resource Adequacy — Design Criteria**
> Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation

> [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

The Northeast Power Coordinating Council has in place a comprehensive resource assessment program directed through NPCC Document B-08, "Guidelines for Area Review of Resource Adequacy (http://www.npcc.org/documents/regStandards/Guide.aspx)." This document charges the TFCP to assess periodic reviews of resource adequacy for the five NPCC Areas.

The primary objective of the NPCC Area resource review is to ensure that plans are in place within the Area for the timely acquisition of resources, sufficient to meet this resource adequacy criterion. Further the objective is to identify those instances in which a failure to comply with the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or other NPCC criteria, could result in adverse consequences to another NPCC Area or Areas. If, in the course of the study, such problems of an inter- Area nature are determined, NPCC informs the affected systems and areas, works with the area to develop mechanisms to mitigate potential reliability impacts and monitors the resolution of the concern.

Document B-08 requires each area resource assessment to include an either an evaluation or discussion, or both of the:

- load model and critical assumptions on which the review is based;
- procedures used by the area for verifying generator ratings and identifying deratings and forced outages;
- ability of the area to reliably meet projected electricity demand, assuming the most likely load forecast for the Area and the proposed resource scenario;
- ability of the area to reliably meet projected electricity demand, assuming a high growth load forecast for the area and the proposed resource scenario;
- impact of load and resource uncertainties on projected area reliability, discussing any available mechanisms to mitigate potential reliability impacts;
- proposed resource capacity mix and the potential for reliability impacts due to the transportation infrastructure to supply the fuel;
- internal transmission limitations; and
- the impact of any possible environmental restrictions.

The resource adequacy review must describe the basic load model on which the review is based together with its inherent assumptions, and variations on the model must consider load forecast uncertainty. The anticipated impact on load and energy of demand-side management programs must also be addressed. If the area load model includes pockets of demand for entities, which are not members of NPCC, the area must discuss how it incorporates the electricity demand and energy projections of such entities.

Each area-resource adequacy review will be conducted for a window of five years, and a detailed, "Comprehensive Review," is conducted triennially. For those years when the

Comprehensive Review is not required, the area is charged to continue to evaluate its resource projections on an annual basis. The area will conduct an "Annual Interim Review" that will reassess the remaining years studied in its most recent Comprehensive Review. Based on the results of the Annual Interim Review, the area may be asked to advance its next regularly scheduled Comprehensive Review.

These resource assessments are complemented by the efforts of the Working Group on the Review of Resource and Transmission Adequacy (Working Group CP-08), which assesses the interconnection benefits assumed by each NPCC area in demonstrating compliance with the NPCC resource reliability. The Working Group conducts such studies at least triennially for a window of five years, and the Working Group judges if the outside assistance assumed by each area is reasonable.

Wind Energy Development

Energy produced by wind will continue to increase in NPCC. For the summer of 2009, the following contribution from wind generation is projected:

Table NPCC - 2: 2009 Wind Energy Development, Summer 2009 Projections		
Sub-Region	Nameplate Capacity	Capacity After Applied De-Rating
Maritimes	349.16 MW	151.7 MW
New England	100 MW	87 MW
New York	1,273 MW	127.3 MW
Ontario	1,084 MW	119.2 MW
Québec	532.3 MW	0 MW
TOTAL	3,386.46 MW	485.2 MW

For the summer of 2008, wind generation estimates were as follows:

Table NPCC - 2: 2009 Wind Energy Development, Summer 2008 Estimates		
Sub-Region	Nameplate Capacity	Capacity After Applied De-Rating
Maritimes	159.7 MW	43.7 MW
New England	11.1 MW	4.3 MW
New York	424 MW	42.4 MW
Ontario	471 MW	47 MW
Québec	420 MW	0 MW
TOTAL	1,485.8 MW	137.4 MW

NPCC Transmission Assessment Process

In parallel with the NPCC Area resource review, the NPCC Task Force on System Studies (TFSS) is charged with conducting periodic reviews of the reliability of the planned bulk power transmission systems of each Area of NPCC, the conduct of which is directed through NPCC Document B-04, "Guidelines for NPCC Area Transmission Reviews (http://www.npcc.org/documents/regStandards/Guide.aspx).” Each area is required to present an annual transmission review to the TFSS, assessing its planned transmission network four to six years in the future. Depending on the extent of the expected changes to the system studied, the review presented each year by the area may be one of the following three types:

- Comprehensive Review — A detailed analysis of the complete bulk power system of the Area is presented every five years at a minimum. The TFSS will charge the area to conduct such a review more frequently as changes may dictate.
- Intermediate Review — An Intermediate Review is conducted with the same level of detail as a Comprehensive Review, but in those instances in which the significant transmission enhancements are confined to a segment of the area, the review will focus only on that portion of the system. If the changes to the overall system are intermediate in nature, the analysis will focus only on the newly planned facilities.

- Interim Review — If the changes in the planned transmission system are minimal, the area will summarize these changes, assess the impact of the changes on the bulk power system of the area and reference the most recently conducted Intermediate Review or Comprehensive Review.

In the years between Comprehensive Reviews, an area will annually conduct either an Interim Review, or an Intermediate Review, depending on the extent of the system changes projected for the area since its last Comprehensive Review. The TFSS will judge the significance of the proposed system changes planned by the area and direct an Intermediate Review or an Interim Review. If the TFSS agrees that revisions to the planned system are major, it will charge a Comprehensive Review in advance of the normal five-year schedule.

Both the Comprehensive Review and the Intermediate Review analyze:

- the steady state performance of the system;
- the dynamic performance of the system;
- the response of the system to selected extreme contingencies; and
- the response of the system to extreme system conditions.

Each review will also discuss special protection systems and / or dynamic control systems within the area, the failure or misoperation of which could impact neighboring areas or Regions.

The depth of the analysis required in the NPCC transmission review fully complies with, or exceeds, the obligations of NERC Reliability Standards TPL-001 through TPL-004:

- TPL-001-0, “System Performance Under Normal Conditions”
- TPL-002-0, “System Performance Following Loss of a Single BES Element”
- TPL-003-0, “System Performance Following Loss of Two or More BES Elements”
- TPL-004-0, “System Performance Following Extreme BES Events”

Subregions

Maritime Area

Demand

The Maritime Area is a winter peaking system. The Maritime Area load is the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Administrator). As such, it does not take the effect of load coincidence within the week into account. Economic assumptions are not made when determining load forecasts. The Maritime Area does not address quantitative analyses to assessing the variability in projected demand due to weather, the economy, or other factors.

The actual peak for 2008 summer was 3,414 MW on July 25, 2008. This was approximately 128 MW (3.6 percent) lower than last year's forecast of 3,542 MW. Based on the Maritime Area 2009 demand forecast, a peak of 3,529 MW is predicted to occur for the summer period, June through September. The 2009 demand forecast is lower by 13 MW (0.37 percent) when compared to the 2008 demand forecast.

The Maritime Area load is the mathematical sum of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Administrator.)

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

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

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

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

The Maritime Area load is the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Administrator.) The actual peak demand is calculated as the total hourly coincident peak on weekly basis for each sub-area. The Maritime Area is a winter-peaking area.

The Maritimes Area is broken up into sub-areas and each area has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heating, as the Maritimes Area is a winter peaking system. For further information on the energy efficiency programs please review the following links:

www.maritimeelectric.com
www.nppower.com
www.mainepublicservice.com
www.emec.com
www.nspower.ca/energy_efficiency/programs/

Load Management is not included in the resource adequacy assessment for the Maritime Area. In the Maritime Area there is between 435 and 454 MW of interruptible demand available during the assessment period; there is 439 MW forecasted to be available at the time of the Maritime Area seasonal peak.

Generation
The Maritime Area resources will be 7,256 MW of existing capacity plus 0.6 MW (nameplate capability) of planned wind generation scheduled to come on line between June 1, 2009 and September 30, 2009. Of the existing capacity there is 151.7 MW of wind expected on peak and 155.4 MW of biomass.

Capacity Transactions on Peak
There are no purchases from other Regions or subregions that would affect the reserve margins in the Maritime Area. There is a firm sale of 207 MW, including losses, to Hydro-Quebec, which is tied to specific generators. The Maritime Area does have agreements in place for the purchase of emergency energy with other subregions as well as a reserve sharing agreement within NPCC. However, the Maritime Area does not rely on this assistance when doing its assessment.

Transmission Assessment
The Maritime Area does not have any transmission under construction or planned for the 2009 summer that would have any impact on the bulk power system. The Maritime Area does not have any transmission constraints that could impact reliability.

Operational Issues (Known or Emerging)
There are no major generating unit or transmission facility outages anticipated for the summer that will impact reliability in the Maritime Area. Furthermore, there are no environmental or regulatory restrictions that could impact reliability in the Maritime Area. The Maritime Area is forecasting normal hydro conditions for the 2009 summer assessment period. The Point Lepreau generation station will be out of service during the entire summer assessment period. The Maritime Area is a winter peaking system, therefore extreme hot weather conditions studies are not performed. The amount of wind generation presently operating does not require any operational changes. The New Brunswick System Operator does not expect any unusual operating conditions for the summer that will impact reliability in the Maritime Area.

Reliability Assessment Analysis

The Maritime Area assesses its seasonal resource adequacy in accordance with NPCC C-13 Operational Planning Coordination procedure. To fulfill this, the Maritime Area conducts an 18-month load and resource balance assessment in accordance with the procedure. As such, the assessment considers the regional Operating Reserve criteria to be 100 percent of the largest single contingency and 50 percent of the second largest contingency.

When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritime Area is projecting more than adequate reserve margins above its operating reserve requirements for the 2009 summer assessment period. These reserve margins are generally over 80 percent for the 2009 summer season.

The Maritime Area is a winter-peaking system and resource adequacy is generally not a concern during the summer operating period. No external resources were used by the Maritime Area to meet reserve margins during 2008 summer and none are used for the 2009 summer period. The Maritime Area does have agreements in place for the purchase of emergency energy with other subregions as well as a reserve sharing agreement within NPCC. But the Maritime Area does not rely on this assistance when conducting the summer assessment.

The projected monthly reserve margins are very high (near or above 70 percent) for both the 2009 summer and 2008 summer periods.

The only demand response considered in resource adequacy assessment for the Maritimes Area is interruptible load. The Maritimes Area uses a 20 percent reserve criterion for planning purposes and this is equal to 20 percent (Forecast Peak Load MW — Interruptible Load MW), following Federal/Provincial initiatives on wind energy.[61]

Based on these figures, the Maritimes Area projection for wind is close to 1,500 MW by 2016. Renewable Portfolio Standards targets are included in the resource adequacy assessment as forecast generation resources.

No unit retirements are scheduled that would impact reliability.

To ensure seasonal resource adequacy, the Maritime Area conducts an 18-month load and resource balance assessment in accordance with NPCC C-13 Operational Planning Coordination procedure. In the Maritime Area deliverability of generation to load is not a concern, operationally, as there are no transmission constraints or zonal issues within the area.

The Maritime Area does not consider potential fuel-supply interruptions in the Regional assessment. The fuel supply in the Maritime Area is very diverse and it includes nuclear, natural gas, coal, oil (both light and residual), oil/pet-coke, hydro, tidal, municipal waste, wind, and wood. As for the potential of a gas supply shutdown during the month of August, no reliability issues are expected to occur. Net reserve margins are still in the 40 percent range. The Maritime Area is forecasting normal hydro conditions for the 2009 summer assessment period. The

[61] http://www.canwea.ca/images/uploads/File/Fed%20and%20provincial%20initiatives-%20Feb%202009.pdf

Maritime Area hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily used as peaking units or providing operating reserve. The Maritime Area is not presently in a drought nor does it anticipate one.

The latest study of interregional transfer capability was conducted as part of the International Power Line/Northeast Reliability Interconnection (IPL/NRI: Pt. Lepreau-Orrington 345 kV) interconnection addition studies on the NB/ISO-NE interface. The region's import capabilities are based on real-time values based on transmission and generation being in/out of service. NBSO has rules based on study results for simultaneous transfer capability on the interconnections. Transmission or generation constraints are recognized that are external to the Maritime Area.

Studies for the International Power Line/Northeast Reliability Interconnection (IPL/NRI) project 345 kV addition included PSSE — dynamic, thermal, and voltage studies and small signal studies were completed using EMTP. There are no anticipated stability issues during 2009 summer. NBSO and NSPI maintain dynamic reactive reserves in voltage sensitive areas. These are monitored by their respective SCADA systems and alarms are programmed to ensure dynamic reactive reserve margins are maintained. Generation and or synchronous condensers are dispatched accordingly to meet the studied margin requirements.

Because of the characteristics of the power system, the Maritime Area does not have any transmission constraints that could impact reliability. In addition the Maritime does not develop an extreme (e.g., 90/10) winter forecast in its seasonal assessment. In summary, no significant reliability concerns are expected for 2009 summer.

There are no dynamic or static limited areas on the bulk power system for the 2009 summer assessment period and there are no anticipated impacts on reliability due to economic conditions in the Maritime Area.

The Maritime Area is not anticipating any reliability concerns during the 2009 summer. Therefore, no additional actions to minimize reliability impacts needed to be taken.

Maritime Area Description

The Maritime Area is a winter-peaking system. This area covers approximately 57,800 square miles serving a population of around 1,910,000. It includes New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Administrator (parts of northern and eastern Maine). In the Maritime Area, New Brunswick and Nova Scotia are Balancing Authorities.

New England

Demand

ISO New England's Balancing Authority area actual 2008 summer peak load, which occurred June 10, 2008, was 26,111 MW. The reference peak load forecast for the summer of 2008 was 27,970 MW. The 2009 summer peak load forecast is 27,875 MW, which is 95 MW (0.3 percent) lower than the 2008 forecast. The key factor leading to this change in the forecast is the ongoing economic recession.

ISO New England (ISO-NE) develops an independent load forecast for the Balancing Authority area as a whole, and does not use individual members' forecasts of peak load in its load forecast.

The reference case forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England 3-day weighted temperature-humidity index (WTHI) of 80.1, which is equivalent to a dry bulb temperature of 90 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The 80.1 WTHI is the 95th percentile of a weekly weather distribution and is consistent with the average of the WTHI value at the time of the summer peak over the last 30 years. The reference demand forecast is based on the reference economic forecast, which reflects the economic conditions that most likely would occur.

It is projected that 506 MW of new energy efficiency programs will be in place by 2009 summer. Along with other types of Demand Resources, energy efficiency programs are considered capacity resources in the New England capacity market. Under the Forward Capacity Market (FCM), which will go into effect on June 1, 2010, energy efficiency can be included in the category of on-peak demand resources. [62] This includes installed measures (e.g., products, equipment, systems, services, practices or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy consumed during on-peak hours. This FCM method is also used for determining resource adequacy in 2009 summer. The ISO has the right to audit the records, data, or actual installations to ensure that the energy efficiency projects are providing the load reduction promised.

In addition to the energy efficiency programs mentioned above, a total of 1,914 MW of demand resources that could be interrupted during times of capacity shortages is assumed available for the summer of 2009. These resources, which are in ISO New England's Real-Time 30-minute, Real-Time 2-Hour, and Profiled Demand Response programs, are instructed to interrupt their consumption during specific actions of Operating Procedure No. 4 (OP 4) Action during a Capacity Deficiency. [63] Some of the assets in the Real-Time Demand Response programs are under direct load control. The direct load control involves the interruption of central air conditioning systems in residential, commercial, and industrial facilities. These direct load control resources are not reported separately from the other assets in the Real-Time Demand Response program.

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[62] The rules addressing the treatment of demand resources in the Forward Capacity Market may be found in Section III.13.1.4 of ISO New England's *Market Rule 1, Standard Market Design*, located at http://www.iso-ne.com/regulatory/tariff/sect_3/2-16-09_mr1_sect_13-14.pdf

[63] http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html

Not included in this assessment is voluntary load that will interrupt based on the price of energy. As of December 31, 2008, there were approximately 86 MW enrolled in the price response program. The actual value of the load that responded is captured in collected demand response data; at the time of the peak in 2008, this figure was about 66 MW.

ISO New England addresses peak demand uncertainty in two ways:

- Weather — peak load distribution forecasts are made based on 37 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded);
- Economics — alternative forecasts are made using high and low economic scenarios.

ISO New England reviews the 2009 summer conditions using the extreme, 90/10 peak demand based on the reference economic forecast. For 2009 summer, that value is 29,780 MW.

Generation

The ISO New England Balancing Authority area Existing-Certain capacity amounts to approximately 33,400 MW based on summer ratings. That consists of 31,225 MW of generating capacity and 2,420 MW of demand resources, including energy efficiency. An additional 218 MW in the Existing, Other category consists of the amount of capacity exceeding 1,200 MW, for those units that exceed 1,200 MW as a single contingency. New England limits its largest single loss of source to 1,200 MW in order to respect operating agreements with PJM and NY. Future generating capacity totaling 228 MW is projected to be in service in time for the summer peak operating period. In addition, there is 68 MW of capacity in the Conceptual category. These resources, which are in ISO New England's Generation Interconnection Queue, have projected in-service dates that would allow them to become commercial in time for the 2009 summer peak.

Approximately 39 MW of the Existing, Certain capacity is wind generation that is expected to be available on peak. The total nameplate capability of those wind facilities is 100 MW. Wind capability is determined from either the sustained maximum net output averaged over a 4 consecutive hour period (measured for the Summer and Winter Capability Periods each year); or the unit's nameplate rating adjusted for engineering data that projects unit output at peak.

The Existing-Certain capacity also includes 1,694 MW of hydro resources that are expected to be available on peak. Monthly ratings for hydro resources with little or no storage are calculated based on the maximum capacity of the unit adjusted for historical stream flow and storage. Those hydro units with storage of at least ten times their Seasonal Claimed Capability (SCC) must demonstrate their summer and winter capability.

Biomass capacity in the Existing, Certain category totals 916 MW. In addition, 8 MW of biomass capacity is in the Conceptual category. No wind, solar, hydro, or biomass projects are included within the 228 MW of future capacity additions that are expected to go into service prior to the summer.

The future resources that ISO New England includes in its reliability analyses and reserve margin calculations are those that have a signed Interconnection Agreement or have received Proposed Plan approval and have begun discussions with ISO-NE Customer Services indicating that the project is nearing completion and is preparing to become an ISO generator asset.

Capacity Transactions on Peak

The forecast of summer firm external capacity purchases is 401 MW. This includes 310 MW from Hydro-Québec and 91 MW from New York. Only firm, Installed Capacity (ICAP) purchases that are known in advance are included as capacity. While the entire 401 MW of ICAP purchases are backed by firm contracts for generation, there is no requirement for those purchases to have firm transmission service. However, it is specified that deliverability of ICAP purchases must meet the New England delivery requirement and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of energy associated with ICAP, but the market participant bears the associated risk of ICAP market penalties if it chooses to use non-firm transmission.

For the summer period, ISO New England expects a firm sale to New York (Long Island) of 343 MW via the Cross Sound Cable. This sale is backed by a firm contract for generation. It can be cut earlier than non-recallable exports in the case of a transmission import constraint into Connecticut.

Transmission

The project that has become known as the Short Term Lower SEMA upgrades is under construction and contains several facilities anticipated to be in service for 2009 summer. This project reduces the reliance on local generating units that are committed to address second-contingency protection for the loss of two major 345 kV lines. The components expected in service in the summer consist of a new 115 kV line and several 345 and 115 kV circuit breakers, a second 345/115 kV autotransformer, and the looping of a 345 kV line into Carver substation. There are no concerns in meeting the target in-service dates of these additions.

The Saco Valley-White Lake 115 kV (Y-138) line addresses the midterm needs of the northern and central New Hampshire system. In addition, the project adds a 115 kV Phase Shifting Transformer and a 115 kV capacitor bank, and involves upgrading a few 115 kV lines. These upgrades are also anticipated in-service by 2009 summer. There are no concerns in meeting the target in-service dates of these additions and upgrades.

During the summer of 2009, no transmission constraints that would significantly impact Regional reliability are anticipated. However, there are localized system concerns where the system is highly dependent upon the operation of available generation. Special operating measures would have to be employed if this generation became unavailable. Short-term transmission upgrades are being implemented where possible to address these concerns, while long-term plans are either being developed or are currently under state siting review. The table below lists significant transmission additions to the bulk power system, which are expected to be in service by 2009 summer and will influence bulk power reliability.

Table NPCC - 3: 2009 Expected Transmission Additions to Bulk Power					
Subregion	**Transmission Project Name**	**Voltage (kV)**	**Length (Miles)**	**In-service Date(s)**	**Description/ Status**
South East Massachusetts	Short Term Lower SEMA Upgrades	115 kV	8.3	Jun-09	Install second circuit from Carver to Tremont.

The table below lists significant transformer additions to the bulk power system, which are expected to be in service by 2009 summer and will influence bulk power reliability.

Table NPCC - 4: 2009 Expected Transformer Additions to Bulk Power System					
Subregion	**Transformer Project Name**	**High-Side Voltage (kV)**	**Low Side Voltage (kV)**	**In-service Date(s)**	**Description/Status**
Maine/New Hampshire	Y-138 Closing Project	115 kV	115 kV	Jun-09	Saco Valley Substation - install one Phase Angle Regulator.
New Hampshire	Monadnock Area	345 kV	115 kV	Jun-09	Fitzwilliam Substation - install one autotransformer.
Southeast Massachusetts	Short Term Lower SEMA Upgrades	345 kV	115 kV	Jun-09	Carver Substation - install second autotransformer.

No other significant substation equipment will be placed in service for the summer of 2009.

Operational Issues (Known or Emerging)

There are no significant anticipated unit outages, variable resource, transmission additions, or temporary operating measures that would adversely impact reliability during the summer. As stated in the Transmission section, new transmission upgrades have been placed in service or are expected to soon be placed in service, which will improve the reliability of various portions of the New England transmission system.

During extremely hot days and low river-flow conditions, there may be environmental restrictions on generating units due to water discharge temperatures. Over the past five years, such conditions have occurred three times, resulting in reductions ranging from 150 MW to 200 MW. These reductions are reflected in ISO New England's forced outage assumptions. The ISO monitors the situation and expects adequate resources to cover such forced outages or generator reductions.

On a monthly basis, ISO New England uses a weekly operable capacity analysis to assess the reliability and adequacy of the Region.[64] The analysis takes into consideration the forecasted

[64] The operable capacity analyses, which are included with ISO-NE's Annual Maintenance Schedule, are posted at http://www.iso-ne.com/genrtion_resrcs/ann_mnt_sched/index.html.

capability of all generators, net firm purchases and sales, the forecasted peak load exposure (both 50/50 and 90/10 forecasts), the operating reserve requirement, and planned and unplanned outages. These analyses do not include demand resources or tie benefits. In order to be prepared for a peak at any time during the summer, ISO New England takes the approach of applying the peak summer demand to not only July and August, but June as well. The operating reserve requirement is 1,800 MW, and the total unplanned outages are assumed to be 3,000 MW in June and 2,300 MW in July through September under both the 50/50 and 90/10 load forecasts. The results are used by ISO New England to identify the means to mitigate problems if any are projected.

At this time, there is minimal penetration of variable or intermittent resources in the overall New England resource mix, so operational changes for the coming summer will not be required. There are no unusual operating issues or concerns that are anticipated to impact the reliable operation of the New England transmission system for the coming summer.

Reliability Assessment Analysis

ISO New England bases its capacity requirements on a probabilistic loss-of-load-expectation analysis that calculates the total amount of installed capacity needed to meet the NPCC once-in-ten-year requirement for preventing the disconnection of firm load due to a capacity deficiency. This value, known as the Installed Capacity Requirement (ICR), was calculated for the 2009/2010 capability year. The ICR is approximately 31,823 MW during July and August, which results in reserves of 14.1 percent. Based on these calculations, ISO New England is projected to meet the NPCC once-in-ten-year resource adequacy criterion.

ISO New England's latest resource adequacy studies are detailed in the report, "ISO New England Installed Capacity Requirements for the 2009–2010 Capability Year."[65]

The model used for conducting the 2009/2010 system-wide ICR calculations for New England accounts for all known external firm purchases and sales, which amount to a net value of 58 MW. This value is the same as the net purchases and sales assumed in 2008/2009. In addition, 2,000 MW of tie benefits from neighboring systems were included in the ICR modeling for both 2008 summer and 2009 summer.

ISO New England assumes that it will be able to obtain 2,000 MW of emergency assistance, also referred to as tie benefits, from other areas within the NPCC Region during any possible capacity shortage conditions. That assumed amount is based on the results of a 2003 probabilistic tie-benefits study. In addition to the tie-benefits study, the ISO has analyzed expected 2009/2010 system conditions of the neighboring Control Areas, as reflected in the most recent Northeast Power Coordinating Council Resource Adequacy Assessment, and determined that the 2,000 MW total tie benefits are reasonable and achievable. The areas assumed to be providing the tie benefits are Maritimes, New York, and Quebec. The tie benefits amount to about 50 percent of New England's total import capability. ISO New England also participates in a Regional reserve

[65] The report "ISO New England Installed Capacity Requirements for the 2009-2010 Capability Year" may be found on ISO-NE's website at http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/index.html.

sharing group with NPCC, and has a shared activation of reserves agreement with New York for up to 300 MW.

For this summer reliability assessment, ISO-NE projects an installed reserve margin of approximately 6,046 MW (21.7 percent) under the reference economic forecast at the 50/50 peak load level forecast, and about 4,141 MW (13.9 percent) under the reference economic forecast at the 90/10 peak load level during the peak load period (July and August 2008). The net reserve margin is based on known outages, anticipated generation additions and retirements, projected firm purchases and sales, and the impact of expected demand response programs. The reserve margin does not include allowances for any unplanned outages or for operating reserve.

Table NPCC - 5: 2008-2009 Projected Reserve Margins		
	(MW)	(MW)
Reference (50/50 Forecast)	4,844	6,046
Extreme (90/10 Forecast	2,919	4,141

The 2008 summer and 2009 projected reserve margins are summarized in the table to the right. The projected reserve margins are sufficient to cover the New England operating reserve requirement, which is approximately 1,800 MW; however, higher than expected unit outages and/or higher than anticipated load could adversely affect the forecasted reserve margin. During the 2008 summer peak-load period, the projected reserve margin under the 50/50 peak load forecast was approximately 4,844 MW, and the reserve margin under the 90/10 forecast was about 2,919 MW. The 50/50 and 90/10 reserve margins forecasted for the 2009 summer are about 1,202 MW and 1,222 MW higher, respectively, than the 50/50 and 90/10 reserve margins forecasted for 2008.

Demand response is treated as capacity in ISO New England's resource adequacy assessment. Demand response availability assumptions used in the assessments are based on performance during OP 4 events or, if no New England-wide OP 4 events occurred during a particular year, on the results of event response audits. The performance of DR resources during specific actions of OP 4 can be monitored by the system operator in real time, and the actual performance during each activation affects the DR resource's compensation on a prospective (going forward) basis. If the ISO does not activate all the DR reliability programs in all Load Zones by August 15th of a calendar year, then the ISO will initiate audits of those programs in the necessary zones.

Renewable Portfolio Standards (RPS) do not impact resource adequacy in New England in a direct way. The revenues from Renewable Energy Credits (RECs) create a financial incentive in the energy market to build renewable resources. The resulting increase in renewable resources leads to increased fuel diversity, which has a positive impact on reliability.

Variable resources are considered similar to other units in ISO New England's resource adequacy assessment in that their ratings are based on expected performance.

The ISO has instituted several processes to aid in the integration of variable resources into ISO planning and operations.

The ISO is now undertaking a study for the New England Governors that will provide a transmission planning service focused on the integration of renewable and carbon-free energy resources in to the power grid. The ISO will assist the New England States in coordination with the region's Transmission Owners in the development of a long-term plan for the New England transmission system that incorporates the unique attributes and goals of each state and the possibility of additional renewable or carbon-free electricity imports from neighboring regions. In addition, the ISO may also provide performance and impact evaluations on various transmission and generation scenarios from both a reliability and economic perspective.

The ISO is about to begin a Wind Integration Study that focuses on what is needed to effectively plan for and integrate wind resources into system and market operations. The main part of the study will focus on developing a mesoscale and wind plant model for the New England area, including onshore and offshore capability. Using those models, the study will look at several wind development scenarios to determine their impact on unit commitment practices, scheduling, automatic generation control, reserves, market operations, and rules as well as other key elements of the system. Another important component of the study will be to plan for and develop technical requirements for new wind resources interconnecting to the system, including the provision for data collection to develop a state of the art wind forecasting tool to use in system and market operations. Finally, the study will look at previous operational studies from around the world and research the most effective tools and processes already in place elsewhere.

The ISO is also assisting new wind park developers in understanding the requirements for interconnection and operating in the New England market through a new generator outreach program facilitated by its customer service department. Topics that are handled in these sessions are intended to assist in the planning process for the ultimate operation of the resources and focus on areas such as determining telemetry requirements, voice communication requirements and system and market operational readiness.

No unit retirements that would have a significant impact on reliability are expected prior to the summer.

ISO New England currently addresses generation deliverability through a combination of transmission reliability and resource adequacy analyses. Detailed transmission reliability analyses of subareas of the New England bulk power system confirm that reliability requirements can be met with the existing combination of transmission and generation. Multi-area probabilistic analyses are conducted to verify that inter-sub-area constraints do not compromise resource adequacy. The ongoing transmission planning efforts associated with the New England Regional System Plan, support compliance with NERC Transmission Planning requirements and assure that the transmission system is planned to integrate generation with load.

In order to ensure that resources are sufficient and deliverable to meet requirements during system peak, ISO New England conducts a Reserve Adequacy Assessment (RAA) based on the forecast demand for the following operating day. The objective of the RAA is to ensure that all identified constraints, including the operating-reserve requirements are met. At all times, ISO-NE must maintain 10-minute reserve equal to its largest first contingency loss, as well as 30-minute reserve equal to one half of its second largest contingency. Operating reserve must be distributed to ensure that the ISO can fully use it for any probable contingency without exceeding transmission system limitations and to ensure reliable operation in accordance with NERC, NPCC, and ISO operating policies and procedures. ISO-NE operating procedures also require the power system be operated such that the loss of any power system element will not cause the post-contingency power flows to exceed either the long-term emergency (LTE) rating for large importing areas or short term emergency (STE) for exporting areas of any other power system element. The impact of first contingency thermal transmission constraints is evaluated in day-ahead and real-time by the power flow and contingency analysis software.

Each day, the ISO identifies transmission interface limits for the next operating day based on first and second contingencies. These limits are used as inputs to develop the day-ahead market schedules, and are periodically updated as part of the daily RAA process. In addition, the ISO's Hourly Capacity Analysis application combines data from several sources to provide a comprehensive assessment of the capacity available versus the capacity needed to meet both the expected demand and reserve requirements for the remainder of the operating day. It calculates the capacity surplus or deficiency within the control area and highlights hours where a deficiency is forecast. The application is rerun every hour with the latest information, including forecast demand and reserve requirements and generator output limitations.

No deliverability concerns for 2009 summer have been identified.

Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. However, ISO New England has been notified of an extended natural gas supply outage scheduled to take place in 2009 summer. The Maritimes and Northeast (M&N) Pipeline has been advised that during the month of August, the Sable Offshore Energy Project will undergo a planned outage lasting approximately 20 days.

ISO New England will monitor the potential for fuel-related constraints on regional generation. Of particular concern is the approximately 1,350 MW of single-fuel, natural-gas fired generation in Maine with no backup fuel capability. The remaining 353 MW of gas-fired generation in Maine has dual-fuel capability. New England's net reserve margin in August under the 90/10 forecast is projected to be 4,141 MW, which is adequate to cover the potential loss of all natural gas-fired generation in Maine. It should be noted that the loss of the M&N gas supply may or may not be an issue on any given day due to the dynamic nature of natural gas dispatch, which reflects the supply and delivery needs of both core and power generation markets.

ISO New England routinely gages the impacts that fuel supply disruptions will have upon system or subregion reliability. Because natural gas is the predominant fuel used to produce electricity in New England, ISO-NE continuously monitors the Regional natural gas pipeline systems, via their Electronic Bulletin Board (EBB) postings, to ensure that emerging gas supply or delivery issues can be incorporated into the daily operating plans. Should natural gas issues arise, which may impact fuel deliveries to Regional power generators, ISO-NE has predefined communication protocols in place with the Gas Control Centers of both regional pipelines and local gas distribution companies (LDCs), in order to quickly notify and implement mitigation measures.

ISO New England, through regular meetings with Regional stakeholders and state and federal regulatory agencies, has established both formal and informal communications links with Regional fuel suppliers. For example, members of the ISO-NE's Electric/Gas Operations Committee (EGOC) routinely inform ISO New England of the status of Regional natural gas (and liquefied natural gas) supply and delivery issues. The EGOC is also fostering efforts to coordinate the Regional maintenance requirements for electric generation, bulk transmission, and Regional gas pipelines and LDCs. In addition, ISO New England's Operating Procedure No. 21 Action during an Energy Emergency[66] is designed to help mitigate the impacts on bulk power system reliability resulting from regional fuel supply deficiencies.

F-Class and higher gas turbines are sensitive to unexpected changes in fuel composition and heat content. The quantity and total capacity of existing and forecast F-Class and higher gas turbines in New England are shown in the table below.

Table NPCC - 6: New England F-Class and Higher Gas Generation Units

Existing/Forecast	Number of F-Class and Higher Units	Total Capacity (MW)
Existing, Certain	39	11,087
Existing, Other		
Existing, Inoperable		
Future, Planned	1	108
Future, Other		
Conceptual		
Total	**40**	**11,195**

An analysis of 2008 NEPOOL (i.e., New England) NERC GADS data was done to search on specific causes of unit reductions or trips due to fuel related issues, specifically searching for issues concerning natural gas heat content or other reportable fuel quality issues related to either domestic or imported natural gas. The NEPOOL 2008 NERC GADS database was searched for plant outage/reduction Component Cause Codes (CCC) = 9205 — Poor Quality Fuel, Heat Content or CCC = 9290 — Other – Fuel Quality Problems, as applied to only gas-fired generation across the New England fleet. The results of this assessment are shown below:

1. All of the NEPOOL 2008 NERC GADS fuel-related events were reported under Component Cause Code (CCC) = 9290 — Other – Fuel Quality Problems.

2. Three (3) units reported natural gas-related fuel issues during the year:
    a. Unit A = One 800 MW nameplate, CC unit, GE 7FA – Class.
    b. Unit B = One 800 MW nameplate, CC unit, Siemens 501G2 – Class.
    c. Unit C = One 200 MW nameplate, CT unit, GE – 7FA – Class.

3. A total of thirty-eight (38) individual GADS events were reported from all three units:
    a. Unit A reported 22 individual events over 14 days.

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

b. Unit B reported 15 individual events over 5 days.
c. Unit C reported 1 individual event on 1 day.
d. There was no overlapping of event days among the units.

4. With respect to reporting the specific details of fuel-related problems arising from the natural gas stream, Unit A reported through NERC GADS one fuel-related event in June 2008 that is of interest. However, the specific details surrounding that event were obtained from other sources (non-NERC GADS). Those details specifically identified problems related to a change in the heat content (Btu/ft3) of the natural gas stream being delivered to the unit's burner-tip. This detailed information may have been misreported via the NERC GADS submittal, as the Component Cause Code (CCC) for the June 2008 event was 9290 — Other – Fuel Quality Problems and NOT the more definitive Component Cause Code of 9205 — Poor Quality Fuel, Heat Content. Other information obtained from non-NERC GADS sources identifies the natural gas pipeline supply for Unit A as the Algonquin Gas Transmission System, owned and operated by Spectra Energy. The fuel event in June was reportedly caused by variations in the heat content of natural gas from domestic supplies not being "commingled," due to a non-typical topology of New England's natural gas pipeline grid. There is no other specific information to report on the other 21 events encountered by Unit A in 2008.

There is no specific information to report concerning natural gas-related problems with the other two Units (B and C) other than Unit B is served by the Tennessee Gas Pipeline and Unit C is served by a local gas distribution company.

As part of its NERC/NPCC mandated seasonal and long-term reliability assessments, ISO New England continually assesses the impacts on the availability of electric power generation due to constraints or contingencies within Regional fuel supply chains, i.e., oil, gas, coal, etc. Due to the over-abundance of gas-fired generation within New England's power generation fleet,[67] ISO New England Inc. (ISO-NE) has specifically studied the potential reliability impacts related to natural gas fuel supplies. Over 20 studies have been performed to date to assess reliability impacts on the electric power grid resulting from a wide range of events occurring on the Regional natural gas supply and transmission systems. Electric sector impacts due to gas sector contingencies, both supply and delivery, have been assessed. While no specific study has been performed to date to assess the vulnerability of electric generation with respect to variations in natural gas fuel quality, other studies have been performed to simulate the loss of gas-fired generation. This "end-effect" — the loss of gas-fired generation, would be a potential result of any natural gas fuel-related issues affecting power generators, so in essence, ISO-NE has studied the potential reliability impacts of variations in natural gas fuel quality.

In addition, ISO-NE has developed new operating procedures that deal with maintaining bulk power supply security during events, which constrain or temporarily interrupt Regional fuel supplies. Another operating procedure was developed that specifically addresses the seasonal

[67] 38 percent (11,948 MW) of New England's total 2009 Summer Capacity (31,443 MW) is fueled by natural gas. 41 percent (over 51 GWh) of New England's overall 2008 historical energy production was fuel by natural gas-fired generation.

impacts on Regional gas-fired generation, which work towards maintaining bulk power system security during periods of extreme winter weather.

ISO-NE has also been monitoring developments within the Regional gas pipeline industry, as they revise the gas quality sections of their tariffs in response to an upcoming influx of liquefied natural gas (LNG) that will be re-gasified into the northeastern U.S./Canadian gas grids. One new Regional LNG project has been recently commercialized and two other projects are expected to be completed by the end of this year. As previously noted, ISO-NE continuously monitors the five Regional interstate pipelines' electronic bulletin boards (EBBs), which provide Critical and Non-Critical Notices to their customers concerning events that may impact fuel deliveries to end-use customers.

Hydro generation contributes to approximately 5 percent of the total New England generation, and hydro conditions are anticipated to be sufficient to meet the expected capability of these plants this summer. The New England area is not experiencing a drought, and reservoir levels are expected to be normal for the upcoming summer.

The import capabilities to New England and the studies on which they are based are listed below. The studies are reviewed and updated as necessary on a regular basis. All of the studies are based on simultaneous transfer capability, recognizing transmission and generation constraints in systems external to New England.

Table NPCC - 7: Import Capabilities to New England and Studies

Interface	Transfer Capability (MW)	Interface Limit
New Brunswick-New England	1,000	Second New Brunswick Tie Study
Hydro-Quebec-New England Phase II	1,200 - 1,400[68]	PJM and NYISO Loss of Source Studies
Hydro-Quebec-Highgate	200	Various Transmission Studies
New York — New England	1,400	NYISO Operating Studies
Cross Sound Cable	346[69]	Cross Sound Cable System Impact Study

The impact of new generator interconnections or changes/additions to transmission system topology on transient performance and voltage or reactive performance of the bulk power system is routinely analyzed and plans are developed to mitigate concerns as part of the interconnection

[68] The Hydro-Quebec Phase II interconnection is a dc tie with equipment ratings of 2,000 MW. Due to the need to protect for the loss of this line at full import level in the PJM and NY Control Areas' systems, ISO-NE has assumed its transfer capability for capacity and reliability calculation purposes to be 1,200 MW to 1,400 MW. This assumption is based on the results of loss of source analyses conducted by PJM and NY.

[69] The transfer capability of the Cross Sound Cable is 346 MW. However, losses reduce the amount of MW that are actually delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal.

process. The most recent system-wide transient stability study was conducted as part of the 2008 Comprehensive Area Transmission Review of the New England Bulk Power System. The results of this analysis are applicable to all seasons and load levels. Additionally, operating studies to develop operating guides are generally performed under light load conditions to assess the impact on transient performance and under both peak and light load conditions to assess the impact on voltage/reactive performance. Therefore, each-and-every change to the generation/transmission system is either implicitly or explicitly evaluated from a transient and voltage/reactive perspective. There is nothing during the study period that would introduce any new concerns in these areas.

New England has specific criteria to manage minimum dynamic reactive reserve requirements. ISO Operating Procedure No. 17 (OP 17) defines acceptable Load Power Factor requirements for various subregions within New England. The procedure is designed to ensure adequate reactive resources are available in the subregion by managing the reactive demand. Furthermore, when transfer limits are developed for voltage or reactive constrained subregions, the ISO will develop detailed operating guides that cover all relevant system conditions to ensure reliable operation of the bulk power system. In determining the acceptable transfer limits, a 100 MW reserve margin is typically added to each limit to ensure that adequate reactive reserves are maintained. In some areas, such as Boston and Connecticut, where specific-reactive compensation concerns exist, specific operating guides have been developed to ensure that the areas are operated reliably.

New England has a specific guideline for voltage sag, which states that the minimum post-fault voltage sag must remain above 70 percent of nominal voltage and must not exceed 250 milliseconds below 80 percent of nominal voltage within 10 seconds following the fault. This guideline is applied when developing transfer limits for the bulk power system in New England.

As previously noted, ISO New England conducts operable capacity analysis for the current year using both a 50/50 and 90/10 forecasts. Those analyses are updated on a monthly basis to reflect the latest information on new generation, purchases/sales and outages.

Studies have been performed in accordance with TPL-001 through TPL-004 as part of the New England Regional System Planning process on both a Regional and localized basis. Some of the larger plans to address future system needs that are currently in process are listed below:

> **Maine** — The Maine Power Reliability Program (MPRP) has found the potential for difficulties in moving power into and through Maine to various load pockets spread throughout the state. The largest of these pockets is the area in southern Maine along the seacoast, including the Portland area. The MPRP proposes numerous system additions to address these concerns. At a high level, these upgrades would create a new 345 kV path extending from Orrington substation in central Maine to Three Rivers switching station in southern Maine.

> **New Hampshire** — A 10-year study of the New Hampshire area has initially identified potential for system concerns throughout much of the state for numerous contingencies and outages. The study of New Hampshire's system is under review. Solutions for

consideration to address system limitations will be investigated upon completion of the 10-year needs assessment.

Vermont — The updated Vermont Long Range Plan (LRP) has identified the potential for system concerns moving power through the state for various contingencies. Moreover, when either a southern 345 kV line or key 345/115 kV autotransformer in the state is lost the next critical contingency would result in numerous thermal and voltage violations in Vermont as well as facilities in neighboring states. Solutions under consideration are being evaluated to address and mitigate the potential for system limitations.

Connecticut — The New England East West Solution (NEEWS) studies have evaluated both the ability of the system to move power from East to West across southern New England and the ability to move power into and across Connecticut. These studies have shown the potential for system limitations preventing necessary transfers in the future. The proposed solution involves new interstate transmission lines from central Massachusetts into Connecticut.

Springfield — The NEEWS studies, resulting in part in the Greater Springfield Reliability upgrades, have shown significant limitations in moving power in and around the Springfield, Massachusetts area. These issues are compounded during times of heavy transfers into Connecticut. These are proposed to be resolved through the elimination of a number of multi-circuit towers in the area and through a new 345 kV overlay between Ludlow, Massachusetts and north-central Connecticut.

Rhode Island — The Greater Rhode Island studies have identified significant constraints on the 115 kV system. The outage of any one of a number of 345 kV transmission lines results in limits to power transfer capability into Rhode Island. For a line-out conditions, the next critical contingency would result in numerous thermal and voltage violations. This is proposed to be resolved by transformer additions and a new 345 kV line between West Farnum and Kent County.

There are no known reactive power-limited areas in the New England transmission system. Transmission planning studies have ensured that adequate reactive resources are provided throughout New England. In instances where dynamic reactive power supplies (DVAR) are needed, devices such as STATCOMs, DVARs and additional generation commitment have been employed to meet the required need. Additionally, the system is reviewed in the near-term via operating studies to develop operating guides to confirm adequate voltage/reactive performance.

In creating transfer limits based on the dynamic performance of the system, New England applies a 100 MW margin to transfer limits.

During 2009 summer, ISO New England does not anticipate any impacts on reliability resulting from economic conditions. As far as capacity is concerned, the ISO does not expect any project cancellations or deferrals. The ISO has a capacity market that pays for resources that contribute capacity to the system, and the economic conditions do not impact the amount of money paid for the capacity. This means that projects that are expected to go into commercial operation in 2009 summer are likely to be in service as planned. With respect to loads, the economic downturn has resulted in a forecasted peak load for 2009 that is 95 MW lower than the 2008 forecast. Therefore, ISO New England's ability to serve the load has increased, and this improves reliability.

New England Area Description

ISO New England is a Regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable operation of New England's bulk power generation and transmission system, and also administers the Region's wholesale electricity markets and manages the comprehensive planning of the regional bulk power system. The New England Regional electric power system serves 14 million people living in a 68,000 square-mile area. New England is a summer-peaking system.

New York

Demand

The actual summer peak demand for the New York Control Area in 2008 was 32,432 MW. The 2008 summer forecast demand was 33,809 MW. The forecast summer peak demand in 2009 is 33,452 MW. The peak demand is the sum of the coincident peak demands of each transmission district in the control area. Each transmission district develops its own Regional load growth factor, based on the economic outlook in the district. All transmission districts considered the economic downturn when developing their 2009 forecast. In addition, most transmission districts took energy conservation into account when developing their load growth projections.

Most transmission districts use a 50th percentile for the expected peak-producing temperature variable or heat index, for which the chance of being over or under is equal in the next year. Two transmission districts use a 67th percentile to select their heat indexes, for which the chance of being under is 2/3 and the chance of being over is 1/3. This produces a higher, more conservative forecast in these districts.

The New York Control Area peak forecast is a coincident forecast, such that the highest load for any given hour over the entire control area is defined as the peak. As discussed in the response to part A), resource evaluations are conducted for the expected coincident peak demand at a 50th percentile for some transmission districts and at a 67th percentile for others.

The conservation programs are specific to each transmission district. The Public Service Commission of New York has instituted an Energy Efficiency Portfolio Standard, which provides goals and timetables for each investor owned utility, together with recommended goals for the state's two power agencies, the New York State Energy Research and Development Agency, and some smaller state agencies. The state is currently establishing measurement and verification protocols to determine the impact of these energy efficiency programs.

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

The Emergency Demand Response Program is designed to reduce power usage through the voluntary shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to take part in the EDRP. The companies are paid by the NYISO for reducing energy consumption when asked to do so by the NYISO.

Special Case Resources is a program designed to reduce power usage through the shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to become SCRs. As part of their agreement, the companies must curtail power usage, usually by shutting down when asked by the NYISO. In exchange, they are paid in advance for agreeing to cut power usage upon request.

The NYISO's Day-Ahead Demand Response Program (DADRP) allows energy users to bid their load reductions, or "negawatts", into the Day-Ahead energy market as generators do. Offers determined to be economic are paid at the market-clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and moderate prices.

As of May 2008 (latest available information), there are 394 EDRP participants representing 363 MW. There are 2,912 SCR participants representing 1,761 MW. There are 20 DADRP participants representing 319 MW.

All SCR and EDRP program participants submit hourly interval data to the NYISO so that actual performance indexes may be calculated. The NYISO files reports to FERC on a periodic basis regarding the performance of these programs.

The NYISO and transmission owners conduct a load forecast uncertainty analysis each year as part of the determination of the NYCA installed reserve margin. The details of this analysis may be found in the following report, New York Control Area Installed Capacity Requirements for the Period May 2009 through April 2010, located at the New York State Reliability Council web site[70], page 33.

The basic procedure is to develop weather response functions at peak load conditions for the several Regions of the control area. A statistical analysis of the temperature and humidity at peak conditions provides the basis for estimating the variability due to weather. Additional multiplicative factors due to high or low economic growth scenarios may also be included.

Generation

For 2009, the New York Balancing Area expects 38,547 MW of existing capacity. Of the existing capacity, 1,273 MW are from wind generation and 357 MW from biomass generation. Capacity classified as "Existing, Certain" total 39,345 MW; the breakdown of certain energy from various generation types are as follows: 127 MW from wind generation, 5,033 MW from hydro generation, and 333 MW from biomass generation.

[70] http://www.nysrc.org/pdf/Reports/2009%20IRM%20Report%20-20Final%2012%2005%2008%20V1.pdf

Capacity classified as "Existing, Uncertain" totals 1,773 MW; the breakdown of uncertain energy from various generation types is as follows: 1,146 MW from wind generation, 603 MW from hydro generation, and 24 MW from biomass generation. Solar energy as capacity is negligible.

NYISO applies a 45 percent derate factor for non-NYPA hydro generation for the expected peak months of July and August. The 45 percent derate factor is applied to the total available non-NYPA hydro generators totaling 1,040 MW. The large NYPA projects (St. Lawrence and Niagara) have specific derate factors based on the probability the unit will be at certain percentages of its rated output. Adding all the hydro generation derates values in New York totals 603 MW.

For wind generation the NYISO derates all wind generators to 10 percent of rated capacity in the summer operating period. With 1,273 MW of wind generation capacity for this summer, the expected on-peak capacity counted is 127.3 MW from wind generators.

Since the summer of 2008, 1,189 MW of additional resources have been added to the New York system. Approximately 849 MW of additional resources are wind project, a 310 MW in combined-cycle unit, and the Gilboa 3 up-rate is 30 MW.

Purchases and Sales on Peak

The NYISO projects capacity backed energy result in net purchases in to the New York Balancing Area backed by 2,412 MW of generating capacity.

Capacity purchases are not required to have accompanying firm transmission but adequate transmission rights must be available to assure delivery to NY when scheduled. External capacity is also subject to external availability rights. Availability on the import interface is available on a first-come first-serve basis. The total capacity purchased for this summer operating period may increase since there remains both time and external rights availability.

Due to NYISO market rules, information on specific import and export transactions is considered confidential. Information on the aggregated or net expected capacity imports and exports during peak summer conditions is not yet known. Capacity is traded in the NYISO market as a monthly product, and total imports and exports are not finalized until shortly before the month begins.

Transmission

The re-conductor of the Northport – Norwalk Harbor 138 kV cable was completed during the summer of 2008. The new cable has three circuits and operates at the same ratings as the current cable. New 230 kV stations have been added to connect the new wind generation that came on-line during 2008. In the North Country, Ryan 230 kV and Duley 230 kV tap the Willis-Plattsburg 230 kV lines. In the western-tier, Wethersfield, High Sheldon, and Canandaigua 230 kV stations have been added tapping the Stolle-Meyer-Hillside 230 kV path.

The Millwood 345 kV 240 Mvar capacitor bank is scheduled to be added by June 2009, for added voltage support in the lower Hudson Valley.

No transmission constraints that could significantly affect reliability have been identified.

The table below lists significant transmission additions to the bulk power system, which are expected to be in service by 2009 summer and will influence bulk power reliability.

Table NPCC - 8: 2009 Expected Transmission Additions to Bulk Power System

Subregion	Transmission Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/ Status
	Millwood Shunt Capacitor	345 kV	-	6/9/09	Add 240 Mvar Capacitor

The table below lists significant transformer additions to the bulk power system, which are expected to be in service by 2009 summer and will influence bulk power reliability.

Table NPCC - 9: 2009 Expected Transformer Additions to Bulk Power System

Subregion	Transformer Project	High-Side Voltage (kV)	Low Side Voltage (kV)	In-service Date(s)	Description/ Status
None					

No other significant substation equipment will be placed in service for the summer of 2009.

Operational Issues

No generation outages scheduled are expected to impact reliability. No abnormal or unusual operating conditions are expected.

The Regional Greenhouse Gas Initiative (RGGI) became effective January 1, 2009. The program is an agreement among ten northeast states designed to reduce the emissions of carbon dioxide from power plants greater than 25 MW. The RGGI system is administered through the use of permits known as allowances. One allowance is required for each ton of CO_2 that has been emitted by an affected facility. RGGI established an annual emissions cap for each of the member states that approximates recent emission patterns. The allowances are mostly distributed through a series of auctions.

Program compliance is measured over a three-year period with the first compliance period running from 2009–2011. If the market price of allowances increases above threshold prices then the compliance period is extended one more year. If the new RGGI Allowance market operates as set forth by the modeling conducted by the state, bulk power system reliability is not expected to be negatively impacted in the near term. If a gas pipeline failure were to cause dual-fueled plants to convert to oil resulting in increased emissions of carbon dioxide and allowances were not available to cover the increased emissions, then some states have provided for the suspension of the RGGI program. New York State Department of Environmental Conservation administers the program in New York. The NYSDEC Commissioner has stated in the rule making process, that in such a situation, he would act to maintain electric system reliability.

There are no low water level concerns in the New York Balancing Area.

No special operational planning studies were required for 2009 summer.

The NYISO currently has 1,273 MW of wind interconnected with 386 MW located in the North Zone (Zone D). The NYISO has had to infrequently limit the total wind output in Zone D to address post contingency flows on the 115 kV transmission system.

In June 2008, the NYISO implemented a centralized program to forecast energy output for interconnected wind generating plants. The wind forecasts are integrated with the Real-time Security Constrained Dispatch (SCD) and the Real-time and Day-Ahead commitment processes. In anticipation of even greater amounts of wind interconnecting to the system, the NYISO is seeking Tariff changes to become effective in May 2009 to improve the integration of wind resources into its SCD. These changes, if accepted, will require wind plants to receive and follow dispatch-down instructions when it is determined that a wind resource's energy output is subject to limitations as identified by SCD.

There are no unusual operating conditions impacting reliability anticipated.

Reliability Assessment Analysis
The NYISO assesses resource adequacy through a series of studies that determine an Installed Reserve Margin (IRM), Locational Installed Capacity Requirements (LCRs), and the maximum amount of Installed Capacity (ICAP) that may come from Areas outside of the NYISO Balancing Authority Area. These studies are conducted on an annual basis in anticipation of an upcoming Capability Year that begins May 1st and ends April 30th.

For the upcoming Capability Year beginning on May 1, 2009, the NYISO will have 39,461 MW of internal ICAP available after considering firm sales and firm long-term purchases. In addition, there are 310 MW of additions undergoing final testing that will be available for the summer peak. Not including 2,100 MW of Special Case Resources (SCRs) discussed below under demand side resources, the NYISO's projected reserve margin, and based on the ICAP peak load forecast of 33,930 MW is 17.2 percent. The NYISO ICAP forecast is developed prior to the April release of the NYISO Load and Capacity – Gold Book forecast; the ICAP forecast is used for ICAP market analysis. This compares to the recently established Installed Reserve Margin requirement of 16.5 percent.

NYISO complies with NPCC and NYSRC resource adequacy criteria of no more than one occurrence of loss of load per ten years due to a resource deficiency, as measured by 0.10 days/year LOLE. The assumptions take into account demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.

The NYSRC establishes the IRM [71] based on a technical study conducted by the NYISO and the Installed Capacity Subcomm ittee (of the NYSRC). This study find the required am ount of installed capacity need ed to m eet the 0.1 days/year LOLE criterion. Following this study, the NYISO conducts the L ocational Instal led Capacity Requirem ents (LCR) study. [72] This study finds the amount of ICAP needed to exist in New York's high-load areas.

For the previous Capability Year (May 1, 2008 to April 30, 2009), 3,280 MW of external ICAP was allowed into the NYISO Capa city Markets. Of that, only 2,735 MW participated. For the upcoming capability year, 3,160 MW are allowed in to the market with several hundred less due to participate.

Restricting the Capacity im ports allows the in terface ties to be used f or em ergency support. During the Installed Reserve Marg in study, the isolated and interc onnected IRMs are calculated. The difference between these numbers gives an indication of the am ount of em ergency assistance that he NYIS O relies on from its neighbors. For the 2009 IR M study, that delta was 5.5 percent, which translates to a value of 1,865 MW.

As stated above, the reserve m argin for the upcom ing year is pr ojected to be 17.2 percent based on capacity of 39,771 M W and a peak load of 33,930 MW. Last year, the capacity totaled 39,371 MW with a peak load forecast of 33,809. This resulted in a reserve margin projection of 16.5 percent before the addition of 1,300 MW of SCRs.

There are two types of dem and re sources consid ered in NYISO's resource adeq uacy studies . The first is emergency demand response. Participation in this program is voluntary at the time of being called and suppliers are only paid for what they provide. They are handled as any load reduction option available to operators on an e mergency basis. The second type of r esource is a Special Case Resource. This supplier is paid like any other capacity resource, which usually means m onthly ICAP paym ents. In addition, they ar e paid for the load th at is reduced or the generation that's produced with their participation. Since these are like a regular reso urce in that regard, th ey are treated like the other capacity in resource adequacy s tudies. Th e have an associated forced outag e rate (effectiven ess factor) and are includ ed when calculating the Installed Reserve Margin.

The Renewable Portfolio Standard (RPS) is implemented by the New York State Energy and Research D evelopment Agency (NYSERDA) . The NYISO works with them to develop a forecast of the renewab le resou rces that will become available in the upcom ing year. This includes units with RPS contracts plus a percentage of the other units that have applied

No adjustments are made for solar which essentially does not exist at this time in New York. For wind units, M W values have been calcu lated from wind speed and related readin gs taken at various sites over the 8,760 hours for various year s. One of these years corresponds with the

[71] Refer t o NYSRC Rep ort titl ed, "New York Con trol Area Installed Cap acity Req uirements for t he Period May 2009 Through April 2010" (December 5, 2008).

[72] Refer to NYISO Re port titled "LOCATIONAL MI NIMUM INSTALLED C APACITY REQUIREMENTS STUDY COVERING THE NEW YORK CONTROL AREA For the 2008 – 2009 Capability Year" (February 28, 2009).

hourly load shape used in the model. Because of this modeling, we have found that the annual capacity factor of the units modeled is approximately 30 percent, looking at only summer hours result in a capacity factor of 10-11 percent.

A series of studies are performed for each new unit applying to interconnect with the grid. These include feasibility studies, System Reliability Impact Studies (SRIS), and cost allocation studies, also called facility studies.

There are no unit retirements impacting reliability for 2009.

The NYISO performs a resource adequacy study to help the New York State Reliability Council determine the required Installed Reserve Margin for the up coming capability year. This study specifies the reserve margin required for the New York Balancing Area. The NYISO conducts the Locational Capacity Requirements study that determines the amount of capacity that must be physically located within specific zones such as New York City and Long Island. The NYISO currently requires that a value of capacity equal to 80 percent of the New York City peak load be secured from within its zone and 99 percent of Long Island peak load be secured from capacity within that zone, for the 2009-2010 capability year. The NYISO also performs an LOLE analysis that determines the maximum amount of ICAP contracts that can originate from Balancing Authorities external to the New York Balancing Authority. The external Area in which the supplier is located has to agree that the supplier will not be recalled or curtailed to support its own loads; or will treat the supplier using the same pro rata curtailment priority for resources within its Control Area. The energy that has been accepted as ICAP in NY must be demonstrated to be deliverable to the NY border. The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to NY.

NPCC requires that New York perform a comprehensive resource adequacy assessment every three years. This assessment uses an LOLE analysis to determine resource needs five years out into the future. A report is required showing how the NYISO would act to meet any projected shortfalls. In the two intervening years between studies, the NYISO is required to conduct additional analysis in order to update the findings of the comprehensive review.

Presently, the New York State Reliability Council (NYSRC) Reliability Rules are implemented such that the electric system has the ability "to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.” Compliance is evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be no more than an average of 0.1 days per year. This evaluation gives allowance for NYS Transmission System transfer capability documented in NYSRC Rules, Installed Reserve Margin (IRM), and Locational Capacity Requirements (LCR) reports. Currently all known deliverability concerns are captured in the evaluation and there are none identified needing mitigation. A multi-area reliability simulation capturing the significant limitations of the NYS Transmission System is performed every year to demonstrate compliance. IRM Requirements are developed annually to satisfy resource adequacy requirements. The NYISO establishes installed capacity requirements (ICAP), including LCRs, recognizing internal and external transmission constraints.

Traditionally, the New York Area generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing generators in southeastern New York have "dual-fuel" capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the summer period.

Reservoir levels are sufficient to contribute to meeting system demand and annual energy requirements. Current reservoir levels from the New York City Department of Environmental Protection show above average water supply. This is due to above average rain and snowfall this winter. The region is not experiencing drought or low water conditions.

The latest study of interregional transmission transfer capability is the *2008/2009 Winter RFC-NPCC Interregional Transmission System Reliability Assessment* (Final report 12/3/2008).

The NPCC Region incremental import capability is 4,500 MW, non-simultaneous. This does recognize transmission and generation constraints in those systems, participating in the study transfers that are external to the Region. This URL, provides a link to study reports performed by the NYISO: http://www.nyiso.com/public/market_data/reports/operational_studies_reports.jsp

As part of NYISO Operating/Planning studies (Seasonal, Short and Long term studies), Interconnection Project Studies, inter-Area and inter-regional studies, NYISO performs the following major assessments to evaluate the reliability of the system.

1. Thermal Contingency Analysis
2. Steady State Contingency Voltage Analysis
3. Voltage Collapse/Voltage Stability Analysis
4. Transient (Angular) Stability Analysis

Based on the results of the studies, there are no known stability issues that could impact the reliability of the system during the 2009 summer season.

Minimum reactive requirements are in the development process. Other than the OP-1 voltage criteria, NYISO does not have voltage-dip criteria.

NYISO's method of ensuring resource adequacy is to plan a system that meets the 0.100 days/year LOLE criteria by setting an appropriate Installed Reserve Margin. To this end, a probabilistic study is performed taking into account Load Forecast Uncertainty. The distribution of this load forecast uncertainty encompasses the 90/10 forecast level along with the corresponding probability that the weather could attain that level. Operationally, operators use may tools to meet the higher loads caused by higher than expected temperatures, such as supplemental calls for generation resources (SRE's) and the Emergency Operating Procedure (EOP) steps.

The NYISO performs transient dynamics and voltage studies. There is no stability issues anticipated that could impact reliability during the 2008 summer operating period. The NYISO does not have criteria for minimum dynamic reactive requirements. Transient voltage-dip criteria, practices or guidelines are determined by individual Transmission Owners in New York State. The NYISO does not use Under Voltage Load-Shedding (UVLS).

The NYISO performs seasonal operating planning studies to calculated and analyze system limits and conditions for the upcoming operating period. The operating studies include calculations of thermal transfer limits of the internal and external interfaces of the New York Balancing Area. The studies are modeled under seasonal peak forecast load conditions. The operating studies also highlight and discuss operating conditions including topology changes to the system (generators, substations, transmission equipment or lines) and significant generator or transmission equipment outages. Load and capacity assessment are also discussed for forecasted peak conditions.

In addition, for TPL-001 through TPL-004, the following studies are performed:

Comprehensive Reliability Planning Process – The NYISO OATT Attachment Y requires an annual planning assessment of transmission and resource adequacy for a 10-year period; while the study focuses on the 5th year and 10th year, all 10 years are evaluated for transmission security and resource adequacy and reliability needs are identified. The complete CRP process is described in the CRPP Manual.

NPCC AREA Transmission Review (ATR) – NPCC Guide B-4 describes the Regional Planning requirements. Areas are required to perform a comprehensive ATR at least once each five years; an Intermediate or Interim ATR may be performed depending on the indicated system changes expected in the horizon year. The ATR focuses on the 5th year.

The Reliability Needs Assessment phase of the CRPP would identify where NPCC Criteria/NYSRC Reliability Rules reliability requirements may not potentially be achieved and request solutions from transmission owners and market participants as provided in the OATT Attachment Y.

The NPCC ATR demonstrates that all NPCC Criteria are met and that the as planned system does not have an adverse impact outside the local area. The Approved NYISO Comprehensive Reliability Plan Final Report demonstrates that all applicable NPCC Criteria, NYSRC Reliability Rules, and NERC Standards can be maintained throughout the 10-year planning horizon, and identifies the necessary system reinforcements and additions to maintain the required level of reliability. The NYISO 2008 Comprehensive Reliability Plan was approved by the NYISO Board of Directors in September 2008.

The NYISO 2005 Comprehensive AREA Transmission Review was submitted to NPCC Task Force on System Studies in January 2006 and approved in May 2006; the NYISO 2006 Interim ATR was submitted to NPCC in January 2007, and approved in March 2007, the NYISO 2007 Interim ATR was submitted to NPCC in December 2007, and approved in March 2008, the NYISO 2008 Intermediate ATR was submitted to NPCC in December 2008, and is presently under review.

There is no anticipated impact on reliability resulting from economic conditions.

Ontario

Demand

Ontario's forecast summer peak demand is 24,998 MW based on Monthly Normal weather and taking into consideration the impacts of planned conservation, growth in embedded generation and the economic retrenchment. The forecast peak for 2009 summer is 3.3 percent higher than the 24,195 MW actual peak demand which occurred on June 9th, 2008. The 2009 forecast is 0.4 percent higher than last summer's weather-corrected peak demand of 24,901 MW. Last summer, the forecasted peak was an almost identical 24,892 MW. The peak remains flat as demand growth from an increasing building stock – primarily residential and commercial – has been offset by reductions due to economic forces and conservation initiatives.

The Ontario Power Authority (OPA) is responsible for promoting conservation and demand management within Ontario. The OPA provides the IESO with projected conservation based on its programs. Validation and verification of these savings are the purview of the OPA. A sizeable number of loads within the province bid their load into the market and are responsive to price and dispatch instructions. Other loads have been contracted by the OPA to provide demand response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and now amounts to approximately 995 MW in total of which 516 MW is included for seasonal capacity planning purposes, with 387 MW of the included amount categorized as interruptible.

The IESO quantifies the uncertainty in peak demand due to weather variation through the use of Load Forecast Uncertainty (LFU), which represents the impact on demand of one standard deviation in the underlying weather parameters. For the upcoming summer peak of 24,998 MW, the LFU is 1,200 MW. Economic factors contribute to the summer peak demand through baseload demand. However, the summer peak is significantly more weather sensitive than any other seasonal peak. That combined with industrial seasonal shutdowns and vacations means that the economic impacts are muted during the summer. The IESO does not anticipate a significant shift in the economic conditions between now and the summer.

Since Ontario is a large geographic area, the IESO uses six weather stations to capture the weather variability across the province. Although the analysis is driven from the system's perspective the individual zones reflect their weather and economic diversity. The IESO addresses summer extreme weather conditions by using the most severe weather experienced since 1970 for each period of the analysis.

Generation

The total capacity of existing installed generation resources (33,121 MW) and loads as a capacity resource (516 MW) connected to the IESO controlled grid is 33,637 MW, of which the amount of 'Certain' capacity is 25,237 MW for June 2009. The remainder, 8,400 MW, is 'Other' capacity for June 2009, which includes the on-peak resource deratings, planned outages, CO_2 emission outages and transmission-limited resources. The certain capacities for July, August and September are 28,010 MW, 28,206 MW and 25,734 MW respectively. No CO_2 emission outages are planned for July and August.

Ontario will have an additional 2,302 MW of new generating capacity for the 2009 Summer Operating period. The following projects are included: the combined cycle portion of the Portland Energy Centre (245 MW), St. Clair Energy Centre (577 MW), Algoma Energy Cogeneration Facility (63 MW), and Enbridge Ontario Wind Farm (182 MW). The Goreway Station Project (839 MW) and Wolfe Island Wind Project (198 MW) are scheduled to be in service before the July peak.

Capacity contribution from wind for the summer months, June, July and August, is assumed at 11 percent of the installed capacity. The wind capacity contribution for September is assumed to be 18 percent. Wind capacity contribution values (the percentage of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median value at the top 5 demand hours of the day for each month. No other variable resources (solar etc) are connected to the IESO controlled grid or are expected to be connected between now and September 2009. The IESO processes are in place to manage the integration of new variable resources such as wind projects.

For wind, the 'Existing, Certain' capacity is 97 MW and 'Existing, Other' capacity is 789 MW for June 2009. These values are 119 MW and 965 MW for July and August and 195 MW and 889 MW for September.

For biomass, the 'Existing, Certain' capacity is 127 MW and 'Existing, Other' capacity is 11 MW for June 2009. These values are 133 MW and 5 MW for July and August and 136 MW and 2 MW for September.

Resources considered under future category are:

- projects that have started commissioning
- projects that are scheduled to be in service within the next three months

The table below shows the amount of future resources that will become available for each month of the summer season.

Table NPCC - 10: 2009 Summer Future Monthly Resources

Month	Nuclear (MW)	Hydroelectric (MW)	Oil/Gas (MW)	Wind (MW)	Biomass/ Landfill Gas (MW)
June		13	823	182	63
July		13	1,662	380	63
August		13	1,662	380	63
September	27	13	1,662	380	63

Capacity Transactions on Peak

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC criteria without reliance on external resources to satisfy normal weather peak demands under planned supply conditions. Day to day, external resources are normally procured on an economic basis through the IESO-administered markets.

For use during daily operation, the IESO has agreements in place with neighbouring jurisdictions in NPCC, RFC and MRO for emergency imports and reserve sharing.

Transmission

The following bulk power system transmission projects are planned before summer.

Table NPCC - 11: 2009 Summer Bulk Power Transmission Projects	
Description	**Proposed I/S Date**
HollandTS: new DESN Station	2009-Q2
Hawthorne TS: new 1,250 MW Ontario-Quec Interconnection	2009-Q2
Middleport TS: new 4x250 Mvar Shunt Capacitors	2009-Q2
Terminate 230 kV circuit C75R (V77R) into Richview T & Claireville TS	2009-Q2

The transmission facilities listed in the table above are currently on schedule for their expected in-service dates. None are critical to the reliability of the bulk system for the upcoming summer. Local reliability improvements are expected for the Holland Transformer Station (TS) addition and the Richview to Claireville circuit. The new Québec interconnection will increase the transfer capability between Ontario and Québec but is not required for reliability needs for this summer. The Middleport capacitors will increase the reactive capability in southern Ontario to allow higher transfers from the west towards the Greater Toronto Area, but these facilities are not expected to be needed to supply the forecast summer demands.

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

There are no bulk power transmissions or transformer additions planned or required to support bulk power reliability for the assessment period.

There are no other significant substation equipment projects planned for the assessment period.

Operational Issues (Known or Emerging)

There are no unusual operating conditions, unit outages, environmental, or regulatory restrictions expected to affect capacity availability for this summer. IESO processes are in place to manage the integration of variable resources, for example wind projects. All known planned generator and transmission outages, along with forecast energy limitations have been included in the IESO's adequacy assessment.

Reliability Assessment Analysis
The IESO uses a multi-area resource adequacy model, in conjunction with power flow analyses, to determine the deliverability of resources to load. This process is described in the document, "*Methodology to Perform Long-Term Assessments*", posted on the IESO website at:
http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

Each year, in compliance with NPCC requirements, the IESO performs a five year LOLE analysis to determine the resource adequacy of Ontario. Every third year, a comprehensive study is conducted, with annual interim reviews between major studies. An interim review done last year showed that Ontario met the requirements. In addition, IESO participates with the other members of NPCC in regional studies, which look at regional long-range adequacy and interconnection benefits between Balancing Authorities in NPCC.

Reserve requirements are established in conformance with NPCC regional criteria. Consistent with historic practices and reporting the IESO does not consider external resources in the calculation of resource adequacy for normal and extreme weather conditions. The resource adequacy studies are done on the last month of every quarter for the next 18 months. The study results are published in the 18-Month Outlook. The link to the report is:
http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2009mar.pdf

The demand forecast is updated on a quarterly basis. The IESO assesses the adequacy and reliability of Ontario's power system for the next 18 months using the updated demand forecast and the results are published in the 18-Month Outlook. The 18-Month Outlook is intended for operational planning purposes, and for scheduling generator outage plans.

The IESO in assessing the resource adequacy considers four scenarios. Planned scenario assumes that all future resources would be available as planned whereas firm scenario assumes only a limited number of future resources. Each of the scenarios is studied with two sets of demand forecast, normal weather and extreme weather.

The reserve margin target used for Ontario is 17.5 percent based on the NPCC criteria. Planning reserves, determined based on the IESO's requirements for Ontario self-sufficiency, are above target levels for all but three weeks in June in this period. As described below, if Ontario market participant actions don't remedy the shortfalls, the IESO has the necessary near-term actions available and the requisite authority to reliably manage this period. On average, the projected reserve margins for the upcoming summer are 1.7 percent higher than the projected reserve margin for the summer of 2008.

Although Ontario does not have an explicit Renewable Portfolio Standard, provincial policy and legislation are influencing electricity infrastructure developments to mitigate air emission and climate change concerns. Specifically, air emission limits have been placed on coal-fired generation, with elimination of coal as an energy source to be achieved by 2014. Renewable energy in the form of wind, solar, hydroelectric and biomass is being aggressively developed in conjunction with major efforts associated with conservation.

There are no units scheduled to be retired over the summer season.

The IESO reviews its system operating limits on an ongoing basis, as warranted by system configuration changes on the grid. In advance of each summer peak season, the IESO analyzes the forecast demand for Ontario, forecast transmission and generation availability, and assesses the deliverability of the planned generation. Where transfer limits are expected to restrict available generation, these restrictions, in addition to zone-to-zone system operating limits, are factored into the reliability analysis for the season, to determine IESO's resource adequacy. The IESO, as the Reliability Coordinator, and via its authority to direct the operation of the IESO-administered market and the IESO-controlled grid, can ensure that generation dispatch does not violate system-operating limits. The generators are expected to reschedule their outages in response to the IESO's adequacy assessment reports (the 18-Month Outlook). If resources remain insufficient in June to satisfy established criteria[73], the IESO will deny final approval for planned outages, may recall CO_2 emission outages and as a last resort can rely on emergency procedures in the operational time frame to address shortfall conditions. The CO_2 emission outages, which limit the CO_2 emissions from the use of coal, are considered for forecasting resource adequacy. However, these outages can be recalled by the IESO in situations when reliability issues exist and the IESO is unable to resolve the problem with other available actions.

The Ontario fuel supply infrastructure is judged adequate during the summer peak demand period, and there are no fuel delivery problems anticipated for this summer. IESO obtains fuel supply information directly from market participants as required. Gas pipeline capacity, historically, has not limited the summer energy or capacity capability of Ontario generation, which is fuelled solely by natural gas and is not expected to be a problem for this summer. Specifically related to the convergence of the natural gas and electricity sectors, the IESO continues to work with the Ontario gas transportation industry to identify and address issues. Similarly, no fuel delivery concerns have been identified for coal-fired or nuclear generating stations. In its market manuals, the IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel-supply limitations are anticipated. No limitations have been reported for the summer months.

IESO resource adequacy assessments include hydroelectric generation capacity contributions based on median historical values of hydroelectric production plus operating reserve provided during weekday peak-demand hours. The capacity assumptions are updated annually, in the second quarter of each year. Energy capability is provided by market participants' forecasts. The amount of available hydroelectric generation is greatly influenced both by water-flow conditions on the respective river systems and by the way in which water is used by the generation owner. Material deviations from median conditions are not anticipated at this time. In the operating timeframe, water resources are managed by market participants through market offers to meet the hourly demands of the day. Since most hydro storages are energy limited, hydroelectric operators identify weekly and daily limitations for near-term planning in advance of real-time operations.

The province is not experiencing a drought at present. Heavy snowfall during the winter months as well as high precipitation throughout past summer caused elevated water levels. This is

[73] NPCC Criteria A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems" and IESO_REP_0531, "Ontario Reserve Margin Requirements"

evident from the monthly water levels report published by Environment Canada. Water levels increased on each of the Great Lakes compared to the levels a year ago.[74]

The IESO annually conducts transmission studies that include results of stability, voltage and thermal and short-circuit analyses in conformance with NPCC criteria. An interim study was conducted in 2008 to comply with the NERC TPL standards, in addition to NPCC criteria.

There are no transmission constraints, stability based limits or reactive power deliverability constraints that are expected to significantly impact reliability based on the forecast availability of generation and transmission facilities for the upcoming season. In the summer, Ontario has an expected coincident import capability of approximately 4,000 MW. It is expected to be augmented further with the new interconnection between Ontario and Québec.

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

Phase angle regulators (PARs) installed on the Ontario-Michigan interconnection at Lambton TS continue to be idle. The failed PAR installed in Michigan on the interconnection between Scott TS and Bunce Creek is scheduled for replacement after the summer of 2009.

The forced outage to the circuit BP 76 on the Ontario-New York interconnection at Niagara continues to reduce the total Ontario-New York import and export capability until its scheduled return to service in Q3 of 2010. This outage results in a reduction of the import and export capability of up to 680 MW. The IESO is monitoring this situation closely and will take the necessary mitigating control actions should this constraint become limiting although at this time the outage is not expected to negatively impact the reliability of the grid

When performing the resource adequacy assessment every three months, the IESO studies four scenarios. Included in the scenarios is an extreme weather scenario. Under extreme weather conditions, the IESO would have to rely on cancelling planned outages, recalling CO_2 emission outages, embarking on emergency procedures and imports.

We have no knowledge of any short term projects being deferred or cancelled due to the current economic climate.

[74] http://www.on.ec.gc.ca/water/level-news/ln200903_e.html

Ontario Area Description

The province of Ontario covers an area of 1,000,000 square kilometres (415,000 square miles) with a population of 12 million. The Independent Electricity System Operator (IESO) directs the operations of the IESO- controlled grid (ICG) and administers the electricity market in Ontario. The ICG experiences its peak demand during the summer, although winter peaks still remain strong.

Québec

Demand

The following table summarizes and compares actual and forecasted demands in Québec for 2008 and 2009.

Table NPCC - 12: Total Summer Internal Demand in MW				
	June	**July**	**August**	**September**
Actual 2008 (A)	20,895	21,220	20,969	21,488
Forecasted 2008 (B)	21,093	21,218	21,452	21,450
Difference (A-B)	-198	2	-483	38
Forecasted 2009 (C)	20,875	20,700	20,988	20,710
Difference (B-C)	218	518	464	740

A general economic slowdown — more precisely some industrial load shutdowns such as sawmills and paper mills — explains the lower 2009 summer demand forecast compared to 2008 summer. It can be seen from the table that the Actual 2008 summer demand came out to be generally lower than the forecast. This year's summer forecast tendency takes the latest data into account.

All the assumptions (economic, demographic and energy-use) are presented at this address: http://www.regie-energie.qc.ca/audiences/EtatApproHQD/Etat-avancement_2008_31oct08.pdf

That document discusses, among other subjects, the following:

- demand and energy forecast by usage
- energy efficiency programs
- resource procurement (demand and energy)
- light and heavy forecast scenarios

Hydro-Québec Distribution is the only Load Serving Entity in Québec. Its load forecast is prepared for the Québec Balancing Authority Area represented as a single entity. There is no demand aggregating.

The Québec Area peak information is coincident. Resource evaluations are based on coincident winter peak forecasts, with light, medium and heavy scenarios.

The demand forecast also takes into account the impact of energy efficiency programs and energy saving trends. Hydro-Québec Distribution promotes the wise usage of electricity as a way to reduce demand. The programs and tools for promoting energy saving are the following:

1. for residential customers Energy Wise home diagnostic
   a. Recyc-Frigo (old refrigerator recycling)
   b. Electronic thermostats
   c. ENERGY STAR qualified appliances
   d. Lighting
   e. Pool-filter timers
   f. ENERGY STAR windows and patio doors
   g. Rénoclimat renovating grant
   h. Geothermal energy
2. for business customers – small and medium power users
   a. Empower program for buildings optimization
   b. Empower program for industrial systems
   c. Efficient products program
   d. Traffic light optimization program
   e. Energy Wise diagnostic
3. for business customers – large power users
   a. Building initiatives program
   b. Industrial analysis and demonstration program
   c. Plant retrofit program
   d. Industrial initiatives program

Program characteristics (in English) can be found at this website address:
http://www.hydroquebec.com/energywise/index.html

Since Québec is a winter peaking Area, no interruptible load programs are required for the summer period.

Climatic uncertainty is modeled by recreating each hour of the last 36-year period of climatic conditions (1971 through 2006) under the current load forecast conditions. Moreover, each year of historical data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend for example.

Hydro-Québec has developed hourly chronological load profiles based on this 36-year analysis of historical weather conditions (1971-2006). This method is useful to quantify weather uncertainty and its impacts on-peak demand. Since Québec has a winter peaking load profile, the uncertainty – measured by a standard deviation analysis – is lower during the summer than during the winter. As an example, at the summer peak, weather conditions uncertainty is about 300 MW, equivalent to one standard deviation. During winter, this uncertainty is approximately 1,200 MW. Extreme weather deviations can be quantified at about 1,100 MW for the summer peak and at about 4,400 MW for the winter peak).

Generation

The amount of Existing (Certain, Other, and Inoperable), Future, and Conceptual capacity resources in-service or expected to be in-service from June 1, 2009 through September 30, 2009 is described below:

The following table summarizes the anticipated '*Existing, Certain*', '*Existing, Other*', '*Existing, Inoperable*' and '*Future*' resources in Québec during the 2009 summer season that were used to fill out Form ERO 2009S.

Table NPCC - 13: Anticipated Resources -Québec Summer 2009

Capacity (MW) in 2009	June	July	August	September
Existing Certain	32,287	33,348	32,069	30,580
Existing Other	8,015	6,953	8,231	9,718
Existing Inoperable	1,897	1,897	1,897	1,897
Total Existing	42,199	42,198	42,197	42,195
Future	101	101	101	101
Conceptual	0	0	0	0
Total Internal Capacity	42,300	42,299	42,298	42,296

The planned capacity additions expected to be in-service during 2009 summer are 48 MW at Chute-Allard hydro G.S. and 53 MW at Rapides- des-Coeurs hydro G.S. (total of 101 MW) The present Québec wind power installed capacity is 531.5 MW. Wind power is completely derated for reliability assessments, so it is included in the '*Existing, Other*' line of the above table. The present Québec biomass installed capacity is 211 MW (forest biomass). Biomass capacity is included in the '*Existing, Certain*' line of the table.

Since the Québec government's adoption of Bill 116 in June 2000, Hydro-Québec Distribution, the only Load-Serving Entity in Québec, has the ultimate responsibility of satisfying the Québec Balancing Authority's electric energy needs. This law enacted Hydro-Québec's functional splitting by establishing four functional divisions within Hydro-Québec and introducing competition in the supply market. To fulfill its obligations, Hydro-Québec Distribution (one of the divisions) inherited an annual volume of patrimonial energy fixed at 165 TWh, supplied by Hydro-Québec Production (another division). This so-called patrimonial contract established the maximum capacity associated with the patrimonial energy at 34,342 MW. Hydro-Québec Production must also provide sufficient reserves to cover the reliability criterion for that patrimonial load. Patrimonial electricity characteristics are fixed by a Québec government decree. The patrimonial contract is characterized by a load duration curve of 8,760 hourly values. Beyond the patrimonial contract, Hydro-Québec Distribution has the legal obligation to use formal calls for tenders to acquire new resources.

A concurrent law concerning the Québec Energy Board obligates (every three years) Hydro-Québec Distribution to produce a Procurement plan describing the characteristics of the contracts it must sign to satisfy the Québec Area's additional needs. Hydro-Québec Distribution must also produce a yearly follow-up of the Procurement plan. The last Procurement plan submitted to the Québec Energy Board, in November 2008 can be found at the following website address: http://www.regie-energie.qc.ca/audiences/EtatApproHQD/Etat-avancement_2008_31oct08.pdf

Since 2002, Hydro-Québec Distribution has proceeded with five long-term calls for tenders in accordance with government decrees for specific supply sources. The first one was not associated with any specific type of generation. The last four concern electricity produced with biomass, wind power and cogeneration. To satisfy its short-term needs, Hydro-Québec Distribution proceeds regularly with short term calls for tenders. Hydro-Québec Production is allowed to participate in these calls for tenders. Each call for tender and contract goes through an approval process with the Québec Energy Board. Moreover, Hydro-Québec Distribution has bought the transmission capacity rights to bring these new resources into the Québec electric market. The transmission network is planned in such manner that new resources related to contracts with Hydro-Québec Distribution can be used for the supply of load without congestion.

Capacity Transactions on Peak

The Québec Balancing Authority Area does not require any external purchase for the 2009 summer peak period in terms of resource adequacy due to its winter peaking characteristic.

On the other hand, Hydro-Québec Production has secured three firm sales during the Summer Operating Period backed by firm transmission contracts:

- Ontario (C.R.T.) 145 MW
- New England 310 MW
- New York 1,165 MW

With these sales, the Québec Balancing Authority Area still has a reserve margin higher than required to meet its resource adequacy criterion. These firm sales also reduce the reserve margin but it still remains higher than the required value.

The entire portion of these sales to Ontario, New York and New England is backed by firm transmission and control area system resources.

Transmission

A few 230 kV transmission additions are scheduled during the 2009 Summer Operating Period to integrate future wind generation projects in the Matapédia region. In the second quarter of 2009, (tentative date is July 2, 2009) TransÉnergie will be commissioning the new Outaouais substation and its interconnection with IESO in the Ottawa-Gatineau area across the Ottawa River. The interconnection consists of two 625-MW back-to-back HVdc converters in Québec and a double-circuit 230 kV line to Hawthorne substation in Ottawa (Ontario). On the Québec side of the converters a 315 kV switchyard will integrate the interconnection into the existing regional system. Chénier 735/315 kV substation, north of Montréal is the source station feeding this interconnection. In 2010, a fourth 1,650 MVA 735/315 kV transformers will be added at Chénier and a new double-circuit 315 kV line from Chénier to Outaouais will permit full use of the 1,250 MW interconnection capacity. It is a possibility, albeit remote, that only one converter will be commissioned in July 2009 and the second converter will be commissioned later during the summer. This would still greatly increase existing interconnection capability between Québec and Ontario and this delay, if it occurs, will not impact bulk power system reliability. This new interconnection is not required for reliability needs for this summer, either in Ontario or in Québec.

No internal transmission constraints that could significantly impact reliability are expected in the Québec Balancing Authority Area. In Québec, transmission and generation maintenance are done during the summer period. However, no maintenance is scheduled that will impact interconnection transfer capability to other subregions during peak periods.

On March 8, 2009, one of the two back-to-back 500-MW HVdc converters at Châteauguay tripped out with multiple thyristor failure (504 failed thyristors) due to a 24 V dc system failure. At that time, the other converter was not in service and did not suffer any damage whatsoever. The second HVdc converter at Châteauguay is therefore available and operating. This HVdc converter is part (with the second converter) of the Châteauguay-Massena interconnection with the New York Balancing Authority Area through Line 7040.

Presently, the converter is scheduled to be back in service May 31, 2009. Meanwhile, import capability into Québec through this interconnection is reduced to 500 MW, from the 1,000-MW normally available capability. Export capability to the New York Balancing Authority Area is not significantly affected since radial generation from Beauharnois G.S. can be routed to the interconnection. The maximum transfer capability under this scenario is 1,500 MW. The interconnection will be under normal operation for the Summer Operating Period with a 1,800 MW transfer capability.

The following tables summarize the transmission and transformer additions in Quebec Québec for the 2009 summer Operating Period.

Table NPCC - 14: Transmission Additions - Quebec Summer 2009 Operating Period

Transmission Project Name	Voltage (kV)	Length (miles)	In-service Date(s)	Description
Outaouais	315/230		Jul-09	HVDC Interconnection with Ontario and related 315 kV and 230 kV equipment
				Status: On time

Table NPCC - 15: Transformer Additions - Quebec Summer 2009 Operating Period

Transformer Project Name	High-side Voltage (kV)	Low-side Voltage (kV)	In-service Date(s)	Description/ status
None				

No other significant substation equipment will be placed in service for the summer of 2009.

Operational Issues (Known or Emerging)
The Québec Balancing Authority Area is a winter peaking system and most unit and transmission maintenance is done during the summer. However, there are no anticipated unit outages, variable resources, transmission outages or temporary operating measures — with the exception of the Châteauguay event previously mentioned — that may impact reliability during this summer. Internal generating unit and transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales and additional uncertainty margins. They should not impact internal reliability and inter-area capabilities with neighboring systems.

There are no environmental, regulatory restrictions, water level or temperature concerns that could impact reliability in the Québec Balancing Authority Area for 2009 summer.

Operational planning studies are being continuously conducted by TransÉnergie, the Québec Area controller. These studies lead to the implementation of procedures to safely operate the system. For example, the Québec system being asynchronous with the rest of NPCC — and being an Interconnection in its own right — has procedures for maintaining spinning reserve (called "stability reserve") to guard against post-contingency frequency drops. In addition, TransÉnergie conducts a yearly peak demand period study to assess system conditions during the winter peak period. No particular operating study has been performed specifically for the 2009 summer period.

Since 2007, Hydro-Québec Distribution uses a commercial system (ANEMOS) to forecast wind power generation. This system has as main input the Environment Canada meteorological forecast with a 15-kilometer (9.3-mile) spatial resolution. Hydro-Québec Distribution produces two to four forecasts per day. If meteorological conditions or the availability of wind generation changes, new wind power generation forecasts are produced. Hydro-Québec Production and Hydro-Québec TransÉnergie both receive the wind generation forecasts. Presently, there are not enough variable resources in the Québec Area to warrant any operational changes on the transmission system.

In summary, no unusual operating conditions are anticipated for the 2009 Summer Operating Period.

Reliability Assessment Analysis
The portions of this section describe the components of the Quebec assessment process.

The projected monthly reserve margins are summarized in the following table.

Table NPCC - 16: Projected Reserve Margins Summer 2009

Reserve Margin	June	July	August	September
In MW	9,992	11,228	9,661	8,450
In % of Net Internal Demand	49	56	47	42

All the assumptions used to establish reserve margin criteria, target margin levels and resource adequacy levels, and results thereof, are discussed in the last Québec Comprehensive Review of

Resource Adequacy (approved by the NPCC on March 11, 2009) and can be found at this website address: http://www.npcc.org/documents/reviews/Resource.aspx.

Each year, the Québec Area has to produce resource adequacy assessments for NPCC and the Québec Energy Board. These assessments are conducted during the fall for the next winter peak period and the years thereafter. The conclusion of the last assessment shows that the Québec Balancing Authority Area's resource adequacy is well beyond the NPCC resource adequacy criterion. During summer months, no external resources are needed to respect the reliability criterion.

The projected reserve margins for 2009 summer are similar to last summer's reserve margins; they are in the 41 to 54 percent range. To calculate these reserve margins, Line 12 (Existing, Certain Capacity and Net Firm Transactions) and Line 3 (Net Internal Demand) of the NERC RAS ERO-2009S worksheet were used.

In Québec, there are two interruptible load programs, although neither is available during the Summer Operating Period. Each program has its own customers. One program cannot be called twice a day and not more than 100 hours per winter period. Therefore, a derate factor (30 percent) is applied to model operational constraints for planning purposes. The other program has conditions that are more flexible, so that a smaller derate factor (15 percent) is applied.

Presently in Québec, wind power is completely derated for the purpose of resource adequacy assessments. However, an operating agreement between Hydro-Québec Distribution and Hydro-Québec Production ensures that wind generation variations are compensated by hydro generation roughly equivalent to the wind farms utilization factor calculated on a yearly basis.

No unit retirement is planned for the Summer Operating Period.

TransÉnergie conducts a yearly peak-demand period assessment for the Québec system to assess generation deliverability during the winter peak period. However, this is done for the winter peak period. For the summer period, when the greater part of system maintenance is done, weekly generation deliverability studies are conducted to assure not only deliverability to internal load but also to interconnections so as to fill-in neighboring Area requirements. When deliverability concerns to interconnections are identified in the summer, maintenance is usually rescheduled so as to maintain scheduled deliveries.

Hydro-Québec Production plans its summer generating unit maintenance so that enough resources are available for internal load and any scheduled exports to neighboring Areas with a sufficient reserve margin to allow for demand forecast uncertainty and unscheduled short term exports. Through the weekly generation deliverability studies mentioned above, TransÉnergie (the transmission operator) assures maximum access to internal and external markets.

Discussion of fuel supplies is not applicable to Québec since about 94 percent of resources are hydroelectric and the system is winter peaking. Fossil fuel generation is used only for peaking purposes in winter and are sufficient to meet both peak demand and the daily energy demand throughout the summer. Reservoir levels are higher than the expected mean levels. To assess its energy reliability Québec has developed an energy criterion that states that sufficient resources should be available to go through sequences of 2 or 4 consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively and having a 2 percent probability of occurrence. These assessments are presented three times a year to the Québec Energy Board.

No drought or drought conditions are presently being experienced or forecasted for the 2009 summer.

Transmission capabilities from and to the Eastern Interconnection are revised periodically with Québec Area's neighboring systems to assess interconnection limits. Transfer capabilities vary from peak to non-peak periods.

The following table indicates the interregional transfer capabilities out of and into Québec with its neighbor systems for the 2009 Summer Operating Period.[75]

Table NPCC - 17: Summer Interconnection Limits in MW

Interconnection	Limit out of Québec	Limit into Québec
Ontario North (D4Z, H4Z)	85	95
Ontario Ottawa (X2Y, P33C, Q4C)	410	32
Ontario Brascan	245	115
Ontario Beauharnois	800	470
Ontario Outaouais (HVDC)	625	1,250
New York (CD11, CD22)	180	100
New York (7040) (HVDC)	1,500 to 1,800	1,000
New England (Highgate) (HVDC)	220	100
New England (Stanstead-Derby)	40	0
New England (Sandy Pond) (HVDC)	1,400 to 2,000	1,800
New Brunswick (HVDC)	691 + radial load	685

These limits recognize transmission or generation constraints in both Québec and its neighbors. They are reviewed periodically with neighboring systems and are posted in the NPCC Reliability Assessments. Those interconnections that are not HVdc are tied to radial generation or radial load.

The reserve margin available in Québec during the summer period ranges from 8,000 to 11,000 MW approximately so that a certain amount of bottling of resources from the Québec Area to the rest of NPCC is expected due to the rated transfer capabilities of the interconnections compared to the available resources. In addition, due to system configuration, capacity may not be available simultaneously to New York and Ontario. However, maximum capacity is made available in July and August for Ontario, New York and New England, with due regard to system constraints concerning exports. Moreover, the transfer capability to and from Ontario will increase significantly when the Outaouais 2 x 625 MW Interconnection is placed in service.

Transient dynamics and voltage stability studies are performed continuously by TransÉnergie to establish system transfer limits on all possible system configurations. No particular issue has been found to impact the 2009 Summer Operating Season. TransÉnergie has a criterion for minimum dynamic reactive requirements. Due to system geography and configuration (generation centers are remote from load centers and system is made up of long 735 kV lines) this is not applied to generators but to synchronous condensers and Static Var Compensators

[75] Limits obtained from the NPCC Reliability Assessment for summer 2009. New York 7040 limited to 500 MW until May 31, 2009

distributed along the system. There are 20 SVCs and synchronous condensers on the system, each with a nominal reactive power range of -100 to +300 Mvar. The steady state operating range is -50 to +50 Mvar per compensator, so that a 250 Mvar margin per compensator is available as dynamic reactive reserve. (Up to 5,000 Mvar total). Moreover, a significant amount of 735 kV 330 Mvar shunt reactors may be switched on and off the system to continually keep the compensators within their operating range. The SVC and synchronous condenser operating range is strictly monitored.

The following table shows the voltage-dip criteria applicable to the Bulk Power System and guidelines after a system contingency.

Table NPCC - 18: Voltage Limits on the Transmission System								
Nominal Voltage	Normal Limits				Emergency Limits			
	Low limit		High limit		Low Limit		High Limit	
	kV	p.u.	kV	p.u.	kV	p.u.	kV	p.u.
735 kV	725	0.985	760	1.034	698	0.95	765	1.04
315 kV	299	0.950	331	1.050	284	0.90	347	1.10
230 kV	219	0.950	242	1.050	207	0.90	253	1.10
Interconnections		0.950		1.050		0.90		1.05

The emergency limits must be respected five minutes after a contingency. This is done automatically by voltage regulation on the system, with the adequate amount of reactive capacity built into the system. However, the 735 kV Emergency Low Limit is quite stringent and the use of MAIS system (Automatic Shunt Reactor Switching System) is used after the contingency to re-establish 735 kV voltages. On the 735 kV system, the transient limit is 0.80 p.u. voltage for two seconds after fault clearing and the mid-term limit is set at 0.90 p.u. from two seconds up to five minutes after fault clearing. All transient and long-term voltage stability analyses must respect these criteria.

As mentioned earlier in this assessment, Québec is winter peaking and the summer peak is roughly 55 percent of the winter peak. Weather conditions will translate into higher demand during the Winter Operating Period. If the summer internal demand is higher than expected, resource adequacy would not be significantly affected.

All operational planning studies done in the Québec Balancing Authority Area are done in compliance with NPCC and NERC planning standards. These include planning studies for the bulk power system, generation integration studies, NPCC reviews, transfer limit studies, etc. The last NPCC Comprehensive Review of the Québec transmission system for 2011-2012 was completed in May 2008. This included assessments for steady-state conditions, transient and voltage stability, fault currents, extreme contingencies, extreme system conditions with reviews of special protection systems and dynamic control systems. The results identified areas to be considered in the final design of the 2012 system such as two series compensation banks to be upgraded and seven breakers in four stations for replacement or for mitigating measures to reduce short-circuit current.

There are no dynamic and static reactive power-limited areas on the Québec Bulk Power System. TransÉnergie does not expect to encounter voltage collapse problems (or even any kind of low voltage problem) during the summer. On the contrary, controlling over voltages on the 735 kV network during off-peak hours is the concern. This is accomplished mainly with the use of shunt reactors. Typically, about 15,000 Mvar of 735 kV shunt reactors may be connected at any given time during the summer, with seven to ten 735 kV lines out of service for maintenance. Most shunt capacitors, at all voltage levels, are disconnected during the summer.

There are no impacts on reliability resulting from economic conditions and there are no other anticipated reliability concerns for the 2009 summer season.

Québec Area Description

The Québec Area is winter peaking. The all-time internal peak demand was 37,230 MW set on January 16, 2009. The summer peak demands are in the order of 21,000 MW. The installed capacity in 2009 is 42,300 MW, of which 38,980 MW (92.1 percent) is hydroelectric capacity. There are 143 generating stations on the system. The transmission voltages on the system are 735, 315, 230, 161 and 120 kV. Transmission line length totals about 32,800 km (20,380 miles).

The Québec Area is a separate Interconnection from the Eastern Interconnection into which other NPCC Areas are interconnected. TransÉnergie ─ the Transmission Owner and Operator in Québec ─ has interconnections with Ontario, New York, New England and the Maritimes. Interconnections consist of either HVdc ties or radial generation or load to and from the neighboring systems. The population served is around 7 million, and the Québec Area covers about 1,668,000 km^2. Most of the population resides along the St-Lawrence River axis and the largest load area is in the Southwest part of the province, mainly around the Greater Montréal area.

NPCC Region Description

NPCC is a New York State not-for-profit membership corporation, the goal of which is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in northeastern North America:

- *through the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability; and*
- *through the establishment of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.*

Geographically, the portion of NPCC within the United States includes the six New England states and the state of New York. The Canadian portion of NPCC includes the provinces of New Brunswick, Nova Scotia, Ontario and Québec. Approximately 45 percent of the net energy for load generated in NPCC is within the United States, and approximately 55 percent of the NPCC net energy for load is generated within Canada. Approximately 70 percent of the total Canadian load is within the NPCC Region. Geographically, the surface area of NPCC covers about 1.2 million square miles, and it is populated by more than 55 million people.

General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of NERC, that has an interest in the reliable operation of the Northeastern North American bulk power system. Full Membership shall be available to entities, which are General Members that also participate in electricity markets in the international, interconnected bulk power system in Northeastern North America. The Full Members of NPCC include independent system operators (ISO), regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America. The current membership in NPCC totals fifty entities.

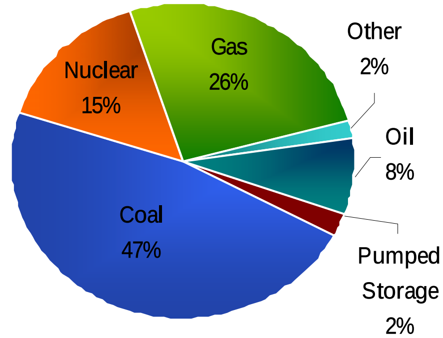
Among the Areas (subregions) of NPCC, Québec and the Maritimes are predominately winter peaking Areas; Ontario, New York and New England are summer peaking systems. (http://www.npcc.org/).

RFC

Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	178,100
Direct Control Load Management	1,300
Contractually Interruptible (Curtailable)	6,900
Critical Peak-Pricing with Control	0
Load as a Capacity Resource	0
Net Internal Demand	169,900

On-Peak Capacity by Fuel Type



2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	177,700	-4.4%
2008 Summer Actual Peak Demand	169,155	0.4%
All-Time Summer Peak Demand	187,893	-9.6%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	213,100	25.4%
Deliverable Capacity Resources	213,100	25.4%
Prospective Capacity Resources	214,400	26.2%
NERC Reference Margin Level	-	15.0%

Introduction

All Reliability*First* Corporation (RFC) members are affiliated with either the Midwest ISO (MISO) or the PJM Interconnection (PJM) regional transmission organization (RTO) for operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission company located in Indiana, Kentucky and Ohio, is not with a member of either RTO and is not affiliated with their markets; however, OVEC's Reliability Coordinator services are performed by PJM. Duquesne Light Co. had previously announced its intention to withdraw from PJM and join MISO in the first quarter of 2009, but recently announced it will remain in the PJM RTO. For this assessment, Duquesne Light is included within the PJM RTO. Also, MISO began operation of its Ancillary Services Market (ASM) on January 6, 2009, which included operation as a single Balancing Authority. More information is available at: http://www.midwestmarket.org/publish/Folder/469a41_10a26fa6c1e_-741b0a48324a.

Reliability*First* does not have officially-designated subregions. About one-third of the RFC load is within MISO and nearly all remaining load is within PJM, except for about 100 MW of load within the OVEC Balancing Authority area. From the RTO perspective, approximately 60 percent of the MISO load and 85 percent of the PJM load is within RFC. The PJM RTO also spans into the SERC Region, and the MISO RTO also spans into the MRO and SERC Regions. The MISO and PJM RTOs each operate as a single Balancing Authority area.

This assessment provides information on the projected resource adequacy for the upcoming summer season across the Reliability*First* Region. The RFC Board recently approved a revision to the Resource Adequacy Assessment Standard BAL-502-RFC-02, which requires Planning

Coordinators to identify the minimum acceptable planning reserves to maintain resource adequacy for their respective areas of RFC. PJM and MISO are the Planning Coordinators for their market areas. The reserve margins in this assessment are based on the explicit probability analyses conducted by these two Planning Coordinators in RFC. Since nearly all Reliability*First* demand is in either Midwest ISO or PJM, the reliability of these two RTOs will determine the reliability of the RFC Region.

Demand

The analysis of the demand data for the summer assessment focuses on three factors, Total Internal Demand (total internal demand), Net Internal Demand (net internal demand) and Demand Response (DR).

Total internal demand represents the entire forecast RTO electric system demand. This demand forecast is based on an average or "50/50" forecast (a 50 percent chance of actual demand being lower and a 50 percent chance of actual demand being higher than the forecast). The Reliability*First* Region identifies the various programs and contracts designed to reduce system demand during the peak periods as DR. Individual companies may implement DR through a direct-controlled load program, an interruptible load contract or other contractual load reduction arrangement. Since DR is a contractual management of system demand, utilization of DR reduces the reserve margin requirement for the RTO. Net internal demand is total internal demand less DR. Reserve margin requirements are based on net internal demand.

Demand Response can be addressed in different ways, reflective of its operational impact on peak demand and reserve margins. DR offers the companies that have these programs and contracts a way to mitigate adverse conditions that the individual companies may experience during the summer. The total demand reduction of each RTO is the maximum controlled demand mitigation that is expected to be available during peak conditions. For the summer of 2009, the RTOs within Reliability*First* have identified the following types of DR programs:

- Direct-controlled Load Management - There are a number of load management programs under the direct control of the system operators that allow interruption of demand (typically residential) by controlling specific appliances or equipment at the time of the system peak. Radio controlled water heaters or air conditioners would be included in this category. Direct controlled load management is typically used for "peak shaving" by the system operators.
- Interruptible Demand - Industrial and commercial customer demands that can be contractually interrupted at the time of the system peak, either by direct control of the system operator (remote tripping) or by the customer at the request of the system operator, are included in this category.

PJM RTO Demand Data

The estimated net internal demand peak of the entire PJM RTO for the 2009 summer season is 127,900 MW and is projected to occur during July. This value is based on the total internal demand forecast prepared by PJM staff with the full use of the load management placed under PJM coordination. The forecast is dated January 2009, and is based on economic data from late 2008, which reflects recent negative economic conditions.

Energy Efficiency programs included in the 2009 load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). At the time of the 2009 load forecast publication, no Energy Efficiency programs have been approved as a RPM resource. At the time of the 2009 load forecast publication, PJM's measurement and verification protocols are under development.

Emergency Load Management placed under PJM coordination is PJM's program for Demand Response. PJM identifies two types of DR, Direct Control and Interruptible. Direct control amounts to 700 MW during the summer for PJM with an additional 5,900 MW of Interruptible Demand.

The estimated total internal demand peak for the entire PJM RTO for the 2009 summer season is 134,500 MW, with 116,200 MW within the RFC area, and is projected to occur during July. This value is based on an independent demand forecast prepared by PJM staff for each PJM zone, region and the total RTO. This compares to the 2008 metered peak demand of 130,100 MW, and a weather normalized peak demand of 136,315 MW. The 2009 forecast total internal demand is 1,815 MW (1.3 percent) lower than the weather normalized 2008 forecast peak total internal demand, and 4,400 MW (3.4 percent) higher than the actual 2008 metered peak demand.

MISO Demand Data

The estimated net internal demand peak of the entire Midwest ISO (MISO) Market Area for the 2009 summer season is 100,100 MW with 62,500 MW within the RFC area. This summer peak is projected to occur in August; however, when the demand forecast data is rounded to the nearest 100 MW, the projected net internal demand is the same in July and August. The net internal demand value is based on the total internal demand forecast prepared by the MISO market participants, which includes Behind-the- Meter demand, and the expected peak reduction from various demand response programs. The MISO market participants developed their demand forecasts at different times throughout the last half of 2008 and early in 2009, so the economic basis for each company forecast reflects the specific economic data of that company's planning area at the time of their forecast.

The amount of MISO market participant demand response or load management expected at the time of the peak is 2,400 MW. This is categorized as 600 MW of Load Management with an additional 1,800 MW of Interruptible Demand.

The estimated total internal demand peak of MISO for the 2009 summer season is 102,500 MW and is projected to occur during August, although the rounded demand data is the same for July and August. This compares to the 2008 metered peak demand of 96,234 MW. Behind-the-Meter demand, which is included in this year's forecast, was netted against BTM generation last year. This change in reporting aggregate demand and the cooler summer weather last year creates an appearance of an increase in the demand forecast. However, a comparison of the 2009 forecast demand to the actual 2008 peak demand (forecast 6,266 MW, 6.5 percent higher), is not meaningful.

RFC Demand Data

In this assessment, the data related to the RFC areas of PJM and MISO are combined with the data from the Ohio Valley Electric Corporation (OVEC) to develop the RFC regional data. The demand forecasts used in this assessment are all based on coincident peak demand, which accounts for the expected demand diversity among the forecasts for the load zones and local balancing areas. Actual data from the past three years indicates minimal diversity between the RTO coincident peak demands and the RFC coincident peak. For this assessment, no additional diversity is included for the RFC Region.

The RFC demand includes 86 percent (109,700 MW) of the PJM RTO demand and 60 percent (60,100 MW) of the MISO market load is within the RFC Region. OVEC is not a member of either RTO market. The OVEC demand of approximately 100 MW is added to the demand of the PJM and MISO areas. The resulting coincident peak forecast for this summer for the RFC Region is 172,700 MW net internal demand and 169,900 MW total internal demand. The forecast net internal demand peak is 7,800 MW (4.4 percent) lower than the forecast demand for 2008. This lower forecast is the result of lower expected economic growth at the time of the demand forecasts. The forecast total internal demand peak is 8,945 MW higher than the actual peak demand of 169,155 MW that occurred on July 17, 2008 for the Reliability*First* regional area. This is due to the forecast being based on normal summer weather conditions and the inclusion in this year's forecast of BTM demand.

Demand Sensitivity

Although the demand forecasts used in this assessment were collected in recent months, some of these forecasts were prepared months earlier. Both weather and economic conditions have significant influence on the peak demands. Any deviation from the original forecast assumptions for those parameters could cause the aggregate 2009 summer peak to be significantly different.

For the summer of 2009, a 90/10 total internal demand forecast was prepared by PJM for its load zones. A 90/10 demand forecast has a 90 percent chance of the actual demand being lower and a 10 percent chance of actual demand being higher. The PJM load zones that are in RFC have a non-coincident 90/10 demand of 123,700 MW, a 6.5 percent increase over the 50/50 demand forecast. MISO performs a statistical analysis with the participant's 50/50 total internal demand forecast and historical demand data to calculate a 90/10 demand forecast. From this analysis, there is a 5.0 percent increase in the 50/50 demand forecast of the RFC area of MISO to 64,900 MW for the 90/10 forecast. For the summer of 2009, the 90/10 net internal demand forecast for the MISO and PJM areas, including OVEC, was used to calculate the sensitivity of the reserve margin to extreme weather in RFC. The results of this demand sensitivity are included in the Reserve Margin Analysis section of this report.

Generation

The generating capacity in this assessment represents the capability of the generation in OVEC and in the PJM and MISO market areas. The capacity category of "Existing, Certain" represents existing resources in PJM's Reliability Pricing Model (RPM) and Capacity Resources (CR) in the MISO market.

The "Existing, Other" resources are the existing generation that represents wind/variable resource deratings, and other existing capacity resources within the Region that are not included in the existing certain category and are not included in the reserve margin calculations. Also included in other existing capacity would be generating capacity that has not been studied for delivery within the Region, and capacity located within the Region that is not part of the PJM RPM or MISO CR.

"Future, Planned" capacity additions are those additions expected to go in-service during the summer period and are included in the determination of the reserve margins. Any "Conceptual" capacity additions are not included in the reserve margins.

The recent emphasis on renewable resources is increasing the amount of wind power capacity being added to systems in the Reliability*First* Region. In this assessment, the amount of available wind power capability included in the reserve calculations is less than the nameplate rating of the wind resources. PJM uses a three-year average of actual wind capability during the summer daily peak periods as the expected wind capability. Until three years of operating data is available for a specific wind project, a 13 percent of nameplate capability is assigned for each missing year of data for that project. In MISO, wind power providers may declare up to 20 percent of nameplate capability as CR. The difference between the nameplate rating and the expected wind capability is accounted for in the "Existing, Other" category.

Scheduled maintenance and any existing capacity that is inoperable for this summer is not included in this assessment of reserve margins. Generally, scheduled maintenance is minimized during the peak demand periods, and is included in the "Existing, Other" capacity category. This scheduled maintenance listed during the summer peak) is expected to be zero for PJM and about 1,900 MW for MISO.

PJM Generation
The entire PJM RTO has 163,400 MW of capacity (140,900 MW within RFC) for this summer that is identified as "Existing, Certain" in this assessment. Under the Reliability Pricing Model (RPM), all capacity that has cleared in the capacity market has to be in service prior to June 1. Therefore, there is no "Future, Planned" capacity included for this summer. There is also 4,400 MW of capacity that can participate in the PJM market as energy-only generation. Since these resources are not in the RPM market, the deliverability of this generation at the time of the peak is uncertain. Therefore, in this assessment none of this capacity is included in the PJM reserve margins.

MISO Generation
The entire MISO RTO has 117,400 MW of capacity (69,800 MW within RFC) for this summer that is identified as "Existing, Certain" in this assessment. No additional capacity is expected to go in service during the summer. However, there is 12,300 MW of capacity in the MISO RTO that is "Existing, Other" capacity, consisting of uncommitted resources, scheduled maintenance, and the derated amount of wind energy capacity. None of this other existing capacity is included in the reserve margin calculation.

RFC Generation
The RFC data only includes generation physically located within the Reliability *First* Region. Generating capacity outside the regional area owned by member companies is included with the scheduled power imports.

The amount of "Existing Certain" OVEC, PJM and MISO capacity in RFC is 212,900 MW. No additional capacity is expected to go in service during the summer. All of the "Existing Certain" capacity in each RTO is determined to be fully deliverable by PJM or MISO within their respective RTOs. There is also 7,100 MW of capacity in the RFC Region designated as "Existing Other" capacity, which is not included in the reserve margin.

Deliverability of capacity between the RTOs is not addressed in this report. However, each of the reserve requirement studies conducted has assumed limited or no transfer capability between these RTOs. Studies by the ERAG indicate there is more than 4,000 MW of additional transfer capability between the RTOs. The limited use of transfer capability in the reserve requirement studies provides a level of conservatism in this resource assessment.

Included in the total of "Existing, Certain" generation is about 300 MW of wind power expected during peak demand conditions. An additional 1,700 MW of wind power is categorized as "Existing, Other" due to the variable nature of wind. There is about 600 MW of biomass generation and 7,000 MW of hydro, including pumped storage hydro, that make up an additional 7,600 MW of renewable generation within the RFC Region.

There are no known adverse weather conditions or fuel supply concerns expected to affect available generating capacity this summer.

Capacity Transactions on Peak

PJM and MISO have reported expected purchases and sales across their RTO boundaries at the time of the peak. This net interchange is due to member ownership interest in generation outside the RTO boundary and contracted transactions. Specific transactions identified by PJM and MISO as interchange with firm transmission reservations that supports the reserve margins in RFC, are included in the reserve margin calculations.

Some of the total interchange reported by PJM and MISO is due to jointly owned generation. These resources are located in one RTO but have owners in both RTOs with entitlements to the generation. Also, some of the interchange in PJM and MISO comes from OVEC entitlements. Since the jointly owned generation and the OVEC generation is all within RFC, the jointly owned and OVEC generation is included in RFC's generation and not the RFC net interchange. There is a net of about 2,200 MW firm transfers from PJM to MISO. These transfers, since they originate and terminate within the RFC Region, will not be included in the RFC interchange. Therefore, the total net interchange for the RFC Region is not a simple summation of the PJM and MISO RTO interchange.

Since both the MISO and PJM balancing authority areas span into neighboring Regions, the values shown below for each RTO are for the total of the respective RTO footprint. The RFC net interchange below only includes that portion of the respective RTOs within the Reliability*First* boundary.

PJM Net Interchange

Firm power transfers into PJM are reported to be 3,700 MW. Firm power transfers out are reported to be 2,300 MW. Net interchange is a 1,400 MW power import flowing into the PJM

RTO. All these imports and exports are firm and fully backed by firm transmission and firm generation.

MISO Net Interchange

MISO only reports power imports to the MISO market. These are reported interchange transactions of 4,300 MW into the MISO market. All these imports are firm and fully backed by firm transmission and firm generation.

RFC Net Interchange

The combined net interchange transactions for OVEC, MISO and PJM at the time of the peak that cross the RFC regional boundary are projected to be a 200 MW import into Reliability*First*.

For both MISO and PJM, any firm capacity from outside the Region could be used for emergency and reserve sharing purposes.

Transmission

Historically, Reliability*First* transmission systems have experienced widely varying power flows due to transactions and prevailing weather conditions across the Region. As a result, the transmission system could become constrained during peak periods because of unit unavailability and unplanned transmission outages concurrent with large power transactions. Generation redispatch has the potential to mitigate these potential constraints. Notwithstanding the benefits of this redispatch, should transmission constraint conditions occur, local operating procedures as well as the NERC transmission loading relief (TLR) procedure are available to maintain adequate transmission system reliability.

Phase Angle Regulators (PARs) are located on all major ties between northeastern PJM and southeastern New York to help control unscheduled power flows. The Ramapo PARs in NPCC control flow from RFC to NPCC. The Michigan-Ontario PARs have not yet achieved long-term operation of all four ties. The B3N line (Bunce Creek [Michigan] – Scott [Ontario]) is in service now; however, B3N PAR is not expected in service this summer. The J5D PAR is in line and controlling flow to minimize overloads as necessary. The L4D and L51D PARs will be bypassed unless under special arrangement between two companies for special conditions. An operations agreement for controlling the interface has been completed for use once all four PARs are in-service and regulating. This delay is not expected to impact reliability.

Many new additions to the bulk-power system since last summer have been placed in-service within the Reliability*First* footprint including a total of 74 miles of transmission line at 100 kV and above, plus two transformers with a total capacity of about 1,200 MVA. An additional total of 50 miles of transmission line at 100 kV and above expects to be placed in-service by this summer, plus ten transformers with a total capacity of about 5,500 MVA. These system changes are expected to enhance reliability of the bulk-power system within Reliability*First*. The tables below show new bulk-power transmission lines and transformers at 230 kV and above which have gone in-service since last summer or will be going in-service this summer:

Table RFC - 1: New Bulk-Power Transmission Lines and Transformers In-Service Summer 2008					
Transmission Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/ Status	RTO
Orchard-Salem-New Freedom	500	15	39,783	In-Service	PJM
North Longview-Fort Martin	500	5	39,934	Under Construction	PJM
Branchburg-Flagtown	230	5	39,934	Under Construction	PJM

Table RFC - 2: New Bulk-Power Transmission Lines and Transformers In-Service Summer 2008					
Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-service Date(s)	Description/Status	RTO
Tallmadge	345	138	Dec-08	In-Service	MISO
Metuchen	230	138	Jan-09	In-Service	PJM
Hiple	345	138	May-09	Under Construction	MISO
Cumberland	230	138	May-09	Under Construction	PJM
Red Lion	230	138	May-09	Under Construction	PJM
Murphy	345	138	Jun-09	Under Construction	MISO
Roseland	500	138	Jun-09	Under Construction	PJM
Brighton	500	230	Jun-09	Under Construction	PJM
Don Marquis	345	138	Jun-09	Under Construction	PJM
Beddington	500	230	Jun-09	Under Construction	PJM
Tangy	345	138	Jun-09	Under Construction	MISO
Avon	345	138	Jun-09	Under Construction	MISO

Other significant substation equipment, such as SVCs, FACTS devices, or HVdc, are not planned for this summer.

Operational Issues (Known or Emerging)

During normal operations and for typical operations planning scenarios, there are transmission constraints within both the PJM and MISO areas of Reliability*First*. All of these constraints may be alleviated with generation redispatch or other operating plans/procedures with minimal reliability impact. The Cook 1 nuclear generator is expected to be out of service this summer due to a recent forced outage. There are a number of new capacitors expected to be placed in-service across the PJM system by this summer resulting in an additional capability of over 1,900 Mvar. Reliability*First* does not anticipate any significant impact on reliability from scheduled generating unit or transmission facility outages.

The output of one power plant in the Washington D.C. area continues to be restricted due to environmental issues. However, the restriction may be lifted for emergency operating conditions. Under extreme hot weather conditions, some units on Lake Michigan may have restricted output if water temperature gets too warm. Additional natural gas fired generation would be used to support any loss. Also, the National Pollutant Discharge Elimination System (NPDES) permits may limit the discharge of water into the Wabash and White Rivers. These permits affect five Wabash River units (668 MW) and two Cayuga units (995 MW) on the Wabash River for the months of May thru October and three Edwardsport units (160 MW) on the White River for the months of June thru September. This risk is mitigated since NPDES permits include a limited number of "exceedance hours" during which the downstream temperature limit is higher. The availability of these units is maximized during peak periods by using exceedance hours. In addition, the risk at Cayuga station has been reduced due to the addition of cooling towers in recent years. Output from all units is always managed to maintain the downstream water temperature within acceptable limits.

Both MISO and PJM conduct summer reliability assessments and both anticipate no unique operational concerns for this summer.

The amounts of distributed and variable generation are relatively small within PJM and are not expected to be a reliability concern this summer. In the East Region of MISO near Chicago, increased congestion is expected during low demand periods (off peak) when wind generation output is high.

No unusual operating conditions that could impact reliability are foreseen for this summer.

Reliability Assessment Analysis

The Reliability*First* 2009 summer resource assessment relies on the reserve margin requirements determined by PJM and MISO to satisfy the Reliability*First* Loss of Load Expectation (LOLE) criterion of not exceeding 0.1 day per year. These analyses include demand forecast uncertainty, outage schedules, and other relevant factors when determining the probability of forced outages exceeding the available margin for contingencies. An assessment of PJM and MISO resource adequacy will be based on the results from these analyses. Therefore, the assessment for the entire Reliability*First* regional area is derived from the results of the PJM and MISO assessments. It is not meaningful to try to calculate a specific reserve margin requirement for all of RFC since each RTO has slightly different demand characteristics, capacity resource availabilities and calculated reserve requirements. However, it follows that when PJM and MISO have satisfied their respective reserve requirements, then RFC can be considered to have sufficient resources.

It is important to note that the capacity resources identified as "Existing, Certain" in this assessment have been "pre-certified" by PJM or MISO for use within their respective RTO market area. This means that these resources are considered fully deliverable within and recallable by their respective markets. Both PJM and MISO include as committed capacity only those generator resources determined to satisfy their respective deliverability requirements. In both RTOs, there are other existing resources may also be available to serve load.

PJM Reserve Margins

The reserve margin requirement for all of PJM is 15.0 percent. This was determined from a study performed by the PJM planning department, and approved by the PJM Board of Managers. Study criteria used in the evaluation can be found in the PJM Planning Manual M-20, "PJM Resource Adequacy Analysis".

The 15.0 percent reserve margin requirement (19,600 MW) in this assessment is based on net internal demand and Net Capacity Resources. The actual reserve margin for the PJM RTO is 36,900 MW, which is 28.9 percent of the net internal demand and is greater than the reserve requirement.

A total of 3,700 MW of resources external to PJM, from the SERC Region, OVEC and from jointly owned generators in MISO, contribute to the PJM reserve margins compared with 2,700 MW for 2008 summer.

MISO Reserve Margins

Under the current Resource Adequacy section of MISO's Energy Markets Tariff (Module E), the reserve margin requirement calculated for the Midwest ISO is 15.4 percent of the net internal demand of its market area. The projected reserve margin for MISO is 21,600 MW, which is 21.6 percent of the net internal demand. Therefore, the reserves are adequate within the Midwest ISO since the available reserves are greater than the reserve requirement of 15,400 MW.

The preliminary report for Midwest ISO's LOLE Study can be found at www.midwestiso.org/publish/Document/20b78d_11ef44fc9c0_-7aa80a48324a?rev=1

RFC Reserve Margins

The calculated reserve margin for Reliability*First* is 43,200 MW, which is 25.4 percent based on net internal demand and Net Capacity Resources. Both PJM and MISO have sufficient resources to satisfy their respective reserve margin requirements. Therefore, the 25.4 percent calculated reserve margin this summer for the Reliability*First* Region is adequate. This compares to a 20.1 percent reserve margin in last summer's assessment.

Both MISO and PJM rely on their markets for satisfying their respective planning reserve requirements; and therefore, do not rely on external emergency assistance.

Renewable Energy

Many states in PJM have Renewable Portfolio Standards (RPS). It is up to the states to promote and provide incentives for renewable development. PJM will assist with the planning studies to build transmission in order to bring the renewable generation into the PJM market. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially use class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor. In order to ensure reliable integration and operation of variable resources, PJM is investigating enhanced methods of regulation such as large utility-scale batteries.

Renewable Portfolio Standards are being included in the current transmission planning studies at MISO. Variable generation resources are currently used to meet load obligation throughout the MISO market footprint as long as they have passed deliverability tests. Wind resources are included with a default of 20 percent of nameplate capacity. The 20 percent value can be increased if proof is given of a more reliable output. This is an interim method, and subject to possible Midwest ISO policy changes.

Generator Retirements

Generator retirements are evaluated for reliability impacts as each retirement is proposed. If PJM determines that a reliability impact exists, the unit will not be allowed to retire until the reliability impacts are addressed. PJM retirement data can be found at http://www.pjm.com/planning/generation-retirements.aspx. MISO expects no unit retirements for this summer.

Fuel

Severe weather conditions or fuel supply and delivery problems can adversely affect available generating capacity. Droughts can affect coal barge traffic on some rivers. Droughts can also impact the cooling water needed for steam generating plants by lowering intake channel depths, or by thermal discharge limitations. Rail bottlenecks or other limitations on rail transportation would be expected to cause significant coal delivery problems. Generation that depends on a single natural gas pipeline can become unavailable during a pipeline outage. Insufficient natural gas in storage during high use periods can create a regulatory prohibition of gas usage for electric generation.

The RFC area is not anticipating drought conditions for this summer. Two thirds of the hydro resources in the Reliability*First* Region are pumped storage units and the remaining are conventional hydro units. These conventional impoundment or run-of-river units only account for about 1 percent of the capacity resources within the Region, limiting the Region's exposure to adverse water conditions.

Natural gas accounts for over 64,000 MW (29 percent) of the regional capacity. Natural gas supply in storage in mid-March was slightly above the 5-year average of gas in storage for that time of year according to the Energy Information Administration. Although natural gas usage for electric generation in the summer has increased significantly in recent years, the peak use of gas for all purposes is during the winter heating season. Reliability *First* does not expect any issues with gas availability this summer.

Coal is a significant fuel within the Region, and a potential concern is the dependence on rail and barge transport for much of the coal supply. However, Reliability*First* is not aware of any major rail transportation limitations or any reported limitations on barge traffic, which would cause concern for this summer.

Reliability*First* members are ready to mitigate any fuel supply disruption that may occur. Although Reliability*First* has not compiled a list of mitigation actions that could be taken, some members may resort to fuel switching for those units with dual-fuel capability, if it becomes necessary to maintain reliable fuel supplies. At least 25 percent of the regional capacity has dual-fuel capability. Reliability*First* has not verified with individual members the ease or difficulty involved with switching to alternate fuels. PJM is investigating firm gas supply contracts. There are significant financial consequences within the PJM market structure for generators who do not supply the requested output when called upon. PJM does not have a policy for on-site coal or back-up fuel storage.

Reliability*First* representatives and staff actively participated in all three of the Eastern Interconnection Reliability Assessment Group (ERAG) interregional seasonal transmission assessment efforts. RFC also conducts its own transmission transfer capability analysis and assessment (see http://www.rfirst.org/Reliability/ReliabilityHome.aspx). Transfer capability results are included in each of the regional and interregional seasonal reports. Simultaneous import capabilities are projected to be adequate for this summer. The table below lists the First Contingency Incremental Transfer Capability (FCITC) determined by the three ERAG study groups for imports into various Reliability*First* areas:

Table RFC - 3: First Contingency Incremental Transfer Capability (FCITC)	
Transfer Direction	**Transfer Capability (MW)**
RFC-MISO to PJM	4,400
PJM to RFC-MISO	No limit found at 5000 MW incremental transfer level
SERC East to RFC-MISO	No limit found at 5000 MW incremental transfer level
SERC East to PJM	3,850
NPCC to RFC-MISO	2,700
NPCC to PJM	2,950
MRO to RFC West	1,100
SPP to RFC West	No limit found at 3000 MW incremental transfer level
SERC West to RFC West	4,400
SERC West to RFC East	2,900

Through regional and interregional transmission transfer capability analysis, Reliability*First* has not identified any dynamic or static reactive power-limited areas. Reliability*First* also does not currently have regional criteria for voltage dip or stability margin, as each individual transmission owner or RTO would develop their own. Voltage stability margin is not a foreseen concern for this summer.

PJM performs voltage stability analysis (including voltage drop) as part of all planning studies and as part of a periodic (every five minutes) analysis performed by the EMS. Results are translated into thermal interface limits for operators to monitor. Transient stability studies are performed as needed and are part of the Regional Transmission Expansion Plan (RTEP) analysis (see http://www.pjm.com/documents/reports/rtep-report.aspx). Small signal analysis is performed as part of long-term studies, but not for seasonal assessments.

Reserve Margin Sensitivity

For the summer of 2009, a higher demand forecast was used to prepare a reserve margin sensitivity case for extreme weather across the Reliability*First* Region. This high demand forecast was developed by combining the 90/10 demand forecasts of PJM and MISO to the OVEC demand. This is not a true 90/10 demand forecast for the Reliability *First* regional area. However, it is being used to evaluate the sensitivity to extreme weather. This forecast amounts to a potential demand increase of about 10,600 MW in July under this weather scenario. On a net internal demand basis, the reserve margin would be 32,600 MW or 18.1 percent.

The above illustrates that high demand due to extreme weather can significantly reduce the reserve margin available (from 25.4 percent to 18.1 percent) to cover potential generator outages. As load increases due to the weather conditions, system operators closely monitor the available generator status and attempt to maintain minimum reserves by purchasing additional power from the interconnection. Curtailment of the interruptible and other Demand Response program loads would precede a public appeal for conservation and any alerts and warnings that would be issued as reserves decline. Such procedures are designed to minimize the potential for curtailing firm load. However, a high level of generator outages coupled with high loads from extreme weather and a lack of additional power available from the other regions of the Eastern Interconnection could result in the curtailment of firm demand. Such a curtailment is considered to have a low probability of occurrence for this summer.

Reliability*First* staff plus MISO, PJM, and the transmission planners within RFC all perform studies to analyze the upcoming summer season in accordance with the requirements in the NERC TPL standards. Results of these studies are summarized in the RFC seasonal transmission assessment report. This report is posted at http://www.rfirst.org/Reliability/ReliabilityHome.aspx.

PJM performs an operational peak self-assessment for anticipated and extreme winter/summer conditions as well as interregional analysis in conjunction with their neighbors to identify potential issues that may arise between areas. No reliability issues are expected this summer.

PJM has developed Reactive Transfer Interfaces to ensure sufficient dynamic Mvar reserve in load centers that rely on economic imports to serve load. PJM day-ahead and real-time security analyses ensure sufficient generation is scheduled and committed to control pre-/post-contingency voltages and voltage drop criteria within acceptable predetermined limits. PJM operates to a reactive transfer limit less than the defined reactive transfer IROL limit.

There are currently three automatic under voltage load shed (UVLS) schemes within RFC. One is located in the northern Ohio/western Pennsylvania area, the second is in the southern Ohio area and the third is in the northern Illinois area. These schemes have the capability to automatically shed a total of about 2,800 MW and provide an effective method to prevent uncontrolled loss-of-load following extreme outages in those areas. There are currently no plans to install new UVLS within the RFC Region for this summer. In addition, under frequency load shedding schemes (UFLS) within the RFC Region are expected to be able to shed the required amount of load during low frequency events.

Even with the current economic downturn, it is difficult to determine the true causes of changes in the numbers of new queued generation projects or queued project withdrawals. Previous cycles have had no correlation to economic trends. Recently, withdrawal of queued projects has increased and recent queues now have less proposed generators. However, it is not expected that the any delay or cancellation of these units will impact reliability within the RFC Region.

Other Region-specific issues

Reliability*First* has no additional reliability concerns for this summer peak season.

Region Description

Reliability*First currently consists of 47 Regular Members, 22 Associate Members, and 4 Adjunct Members operating within 3 NERC Balancing Authorities (MISO, OVEC, and PJM), which includes over 350 owners, users, and operators of the bulk-power system. They serve the electrical requirements of more than 72 million people in a 238,000 square-mile area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. The Reliability*First *area demand is primarily summer peaking. Additional details are available on the Reliability*First *website (http://www.rfirst.org).*

SERC

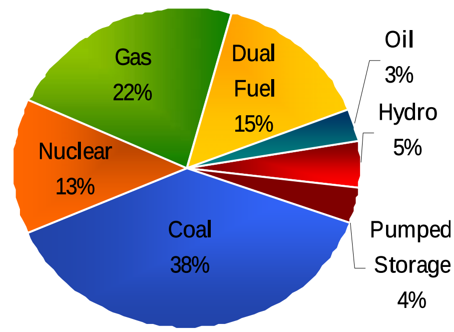
Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	201,364
Direct Control Load Management	960
Contractually Interruptible (Curtailable)	4,946
Critical Peak-Pricing with Control	0
Load as a Capacity Resource	247
Net Internal Demand	195,211

2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	197,040	-0.9%
2008 Summer Actual Peak Demand	197,515	-1.2%
All-Time Summer Peak Demand	209,108	-6.6%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	243,309	24.6%
Deliverable Capacity Resources	243,311	24.6%
Prospective Capacity Resources	257,066	31.7%
NERC Reference Margin Level	-	15.0%

On-Peak Capacity by Fuel Type



Introduction

SERC is the Regional Entity (RE) for all or portions of 16 central and southeastern states. For purposes of reporting data and assessing reliability, the utilities within the SERC Region are assigned to one of five subregions: Central, Delta, Gateway, Southeastern, and VACAR, that together supply power to a population exceeding 70 million or 22 percent of the US population. Most electric utilities within SERC operate under some degree of traditional vertical integration with planning philosophies based on an obligation to serve ensuring that designated generation operates under optimal economic dispatch to serve local area customers. Some utilities in the SERC Region however, have selected or have been ordered to adopt a non-traditional operating structure whereby management of the transmission system operation is provided by a third party under an Independent Coordinator of Transmission or a Regional Transmission Organization (RTO) that manages transmission flows to customers over a broader regional area through congestion-based locational marginal pricing. Companies within SERC are closely interconnected and the Region has operated with high reliability for many years.

It should be noted that the generation capacity figures provided here are based on the data submitted to also fulfill utility reporting requirements under DOE-EIA 411 report. A significant amount of merchant generation has been developed within SERC in recent years, not all of that generation is reflected in the reports presented here. There is an inconsistency between the capacity definitions in the DOE-EIA-411 reporting and the SERC Generation Plant Development Survey. The exact amount of uncommitted is not determinable but it is estimated there is over 4,400 MW of generation in the SERC Region that is in addition to what is reported in the DOE-EIA-411 report. This is a significant improvement in reporting over our 2008 report, which showed 28,000 MW of such generation. In addition, resources and reserve margins provided here are based on firm arrangements in place in early 2009.

Some companies wait to finalize their arrangements until just before the peak season knowing that adequate capacity will be available, usually from pre-existing market structures, where such exist (PJM, MISO). The specific example of this is the utilities in the Gateway subregion, which operate under the MISO market for electricity. Based on reported information at the time of NERC's data collection effort for the Summer Assessment the utilities in the Gateway subregion report an aggregate reserve margin of 9.1 percent, which is less than the MISO resource adequacy margin. We expect (but have no assurance) that the MISO market mechanisms will fill this gap as the summer season progresses. Another factor that should be recognized is an expansion of efforts in efficiency and demand side management (DSM) programs. A number of the utilities in the SERC Region are committing to very aggressive programs that provide means to reduce or curtail demand when needed to ensure reliability. SERC anticipates no difficulties in meeting NERC-specified guidelines of what constitutes appropriate reserve margins for the SERC Region during the 2009 summer peak.

Demand

SERC is a summer-peaking Region. The SERC total internal demand projected for the 2009 summer is forecast to be 201,364 MW, which is 7,744 MW (3.7 percent) lower than the all-time peak of 209,108 MW that occurred in August 2007 and is 1,956 MW (1.0 percent) lower than the forecast 2008 summer peak of 203,320 MW.

This projection is based on average historical summer weather and is the sum of non-coincident forecast data reported by utilities in the SERC Region. Some entities have lowered their forecasts as compared to previous forecasts due to the current economic recession.

Because of the varied nature of energy efficiency programs, they are separately described in the subregion reports of this assessment. A number of utilities in the SERC Region have some form of efficiency program or DSM effort in place or under development.

Traditional load management and interruptible programs such as air conditioning load control and large industrial interruptible services are common within the Region. Interruptible demand and DSM capabilities for 2009 summer are 5,882 MW as compared with the 7,040 MW reported last summer. Traditional demand response programs include monetary incentives to reduce demand during peak periods. Some examples are real-time pricing programs and voluntary curtailment riders. The programs are more fully described in each subregion as part of the more detailed reports below. There are no DSM-related measurement verification programs implemented at the SERC Region level.

Table SERC - 1: Demand Response Programs MW		
Program	**2008 Summer**	**2009 Summer**
Direct Control Load Management	958 MW	960 MW
Contractually Interruptible (Curtailable)	4,977 MW	4,946 MW
Critical Peak-Pricing (CPP) with Control	221 MW	0 MW
Load as a Capacity Resource	125 MW	247 MW
Energy Efficiency Programs	760 MW	748 MW

Ambient temperatures that are higher or lower than normal and the degree to which interruptible demand and DSM is used, result in actual peak demands that vary from the forecast. SERC utilities perform detailed extreme weather and /or load sensitivity analyses in their respective operational and planning studies.

While utility methodologies vary, many common attributes exist. Common attributes include:

- Use of econometric linear regression models
- Relationship of historical annual peak demands to key variables such as weather, economic conditions, and demographics
- Variance of forecasts due to high and low economic scenarios and mild and severe weather
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies utilizing these forecasts.

In addition, many SERC utilities use sophisticated, industry-accepted methodologies to evaluate load sensitivities in the development of load forecasts. Utilities in the SERC Region adhere to their respective state commissions' regulations, RTO requirements, and internal business practices for determining their reserve requirements.

Generation

In aggregate, utilities within the SERC Region expect to have 261,135 MW of resources including 242,006 MW of Existing Certain resources and 16,665 MW of Existing Other resources during the 2009 summer period. SERC reports 2,464 MW of inoperable resources for this upcoming summer. The utilities in the SERC Region anticipate a nominal amount of Future-Planned and Future-Other capacity resources during the period.

Generation facilities are planned and constructed to ensure that aggregate generation capacity keeps pace with the electric demand and allows for adequate planning (and operating) reserves. Among the utilities in the SERC Region, generation reserve capacity is sufficient to mitigate postulated transmission contingencies. Additionally, a number of independent power generating units are interconnected to the transmission system and selling their output into the electricity market where such markets exist within the SERC Region.

While mechanisms exist at state and federal agencies to collect data about the interconnection of new facilities, it is often difficult to accurately capture all of the generation facilities in their various phases of development. In the past, there was a significant mismatch between various reported amounts of generation. For this summer, the amount of mismatch has been reduced from 28,000 MW last year to 4,400 MW, a significant improvement. The ability to rapidly install peaking capacity resources and a general trend toward seasonal and short-term capacity purchases further complicate data collection as many utilities are delaying firm purchase commitments as long as possible. There are however, uncommitted generating plants which are already in service in SERC that have the potential to provide significant resources for certain individual utilities. A good source of information regarding generation development in the SERC Region remains the annual Generation Plant Development Survey. There are minor (but growing) amounts of renewables and variable generation in the Region.

In the SERC Region there has been significant merchant generation development. Some of this merchant generation has not been contracted to serve load within the SERC Region and its deliverability is not assured. For these reasons, only merchant generation contracted to serve load in the SERC Region is included in the reserve margins reported. However, a significant amount of merchant capacity within the Region has been participating in the short-term energy markets, indicating that a portion of these resources may be deliverable during certain system conditions.

The 2009 Generation Plant Development Survey showed approximately 264,300 MW of existing generation as of December 31, 2008. Additions to the generation through the summer assessment period were reported to total 1,838.5 MW with 884.5 MW reported as uncommitted. The uncommitted generation includes 250 MW of wind (200 MW is energy only) and 208.5 MW natural gas where all 208.5 MW is energy only. The Generation Plant Development Survey is a summer rating report and thus provides information that is relevant for the SERC Region summer assessment. Aggregate generating capacity is determined by aggregating the results of individual utility reports to the SERC Portal for data collection. Unit capability is determined by the reporting company.

There are small amounts of Biomass[76] in the SERC Region totaling 248 MW.

Within the SERC footprint, we have utilities that are part of the PJM RTO, which implements and manages a capacity market. MISO operates a centralized energy market, which involves some of SERC's utilities. The remainder of SERC's utilities are traditional, vertically-integrated utilities that do not participate in centralized RTO-based markets.

Capacity Transactions on Peak

Regional sales account for 6,044 MW and regional purchases account for 5,936 MW. These firm purchases have been included in the reserve margin calculations for the Region. Overall, the utilities in the Region are not considered to depend on purchases or transfers outside the SERC Region to meet the demands of the load in the Region.

Table - 2: SERC Region Purchases/Sales MW

Transaction Type	Purchases	Sales
Firm	5,936	6,044 MW
Non-firm	0 MW	172 MW
Expected	0 MW	0 MW
Provisional	0 MW	0 MW

[76] Defined by EIA as: *"organic non-fossil material of biological origin constituting a renewable energy source"*

Transmission

There are no projects anticipated being in service for the 2009 summer that would result in concerns in meeting 2009 summer demand if not completed on time.

There are no transmission constraints that could significantly impact reliability of the utilities in the SERC Region during 2009 summer. Discussions in subregion reports of the assessment for certain utilities indicate a few situations which require monitoring, however nothing significant. With load generally down as compared to the prior year, the system has been tested at greater load levels.

Coordinated interregional transmission reliability and transfer capability studies for the 2009 summer season are conducted among all the SERC subregions and with the neighboring regions. Preliminary results of these studies indicate the bulk transmission systems within the SERC Region have no issues that will significantly impact reliability. No significant limits to transfers were identified except for the Delta-SPP interface. This interface is undergoing planning review by the planning authority.

SERC Region utilities spent approximately $1.32 billion in new transmission lines and system upgrades (includes transmission lines 100 kV and above and transmission substations with a low-side voltage of 100 kV and above) in 2008 and plan to spend approximately $1.42 billion in 2009 and $1.64 billion in 2010.

Details of the transmission line and transformer additions are discussed in the subregion reports including tables showing significant transmission projects.

The SERC Region has extensive transmission interconnections between its subregions. SERC also has extensive interconnections to the FRCC, MRO, RFC, and SPP regions. These interconnections permit the exchange of firm and non-firm power and allow systems to assist one another in the event of an emergency. Approximately 154 miles of 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV transmission lines are scheduled for completion by 2009 summer. There are no concerns with respect to the impact on reliability performance relating to the completion of these projects. SERC has 730 miles under construction, 3,545.1 miles planned or in the conceptual stages at the time of this report.

Plans regarding new SVCs or FACTS controllers to be in service for this coming summer are discussed in each subregion report.

Operational Issues (Known or Emerging)

Most subregions of SERC experienced some drought effects during 2008, although less severe than 2007. SERC conducted a special assessment including an extreme hydrological scenario in excess of forecast 2008 summer conditions. The plans assembled in SERC's 2008 drought study provided a valuable guidance for operations in 2009. If the drought continues through 2009, the conditions leading into 2010 could be somewhat more severe although the long-term trend is improving. At the present time, conditions in 2009 are much improved.

Figure SERC-1: U.S. Drought Monitor – Southeast

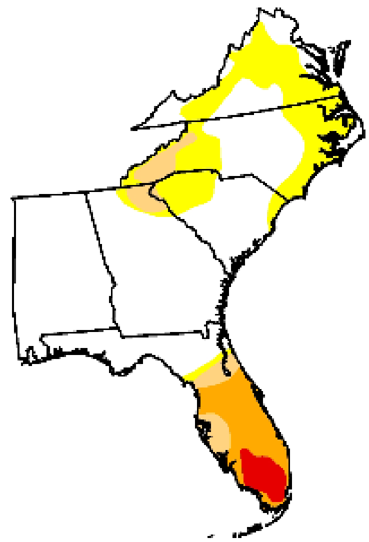
May 5, 2009
Valid 7 a.m. EST

Drought Conditions (Percent Area)

	None	D0-D4	D1-D4	D2-D4	D3-D4	D4
Current	65.8	34.2	14.5	9.3	2.2	0.0
Last Week (04/28/2009 map)	60.8	39.2	14.9	9.3	1.7	0.0
3 Months Ago (02/10/2009 map)	8.9	91.1	20.0	4.6	1.6	0.0
Start of Calendar Year (01/06/2009 map)	65.3	34.7	15.7	5.3	2.8	0.0
Start of Water Year (10/07/2008 map)	35.2	64.8	41.8	20.8	9.4	1.9
One Year Ago (05/06/2008 map)	26.4	73.6	43.6	23.2	8.9	0.0

Intensity:

- D0 Abnormally Dry
- D1 Drought - Moderate
- D2 Drought - Severe
- D3 Drought - Extreme
- D4 Drought - Exceptional



The Drought Monitor focuses on broad-scale conditions. Local conditions may vary. See accompanying text summary for forecast statements

http://drought.unl.edu/dm

Released Thursday, May 7, 2009
Author: Laura Edwards, Western Regional Climate Center

No major generator outages are planned for the summer that could impact bulk power system reliability. No utility identified significant concerns that might threaten reliability for 2009 summer. At most, some redispatch, modest increases in imports, or implementation of operating guidelines may be required. Individual Transmission Planners and Planning Coordinators drought preparedness initiatives are in place.

Environmental restrictions are not expected to significantly impact operations in the SERC Region this summer. With the exception of dams being repaired as noted in the Central subregion report, hydro reservoirs are mostly at or near normal levels as the drought, conditions have improved in many areas.

In general, we expect near-normal rainfall this summer in much of the SERC Region, although in some drought impacted areas rainfall-to-date has been below normal. Much of the Region is recovering from drought; however, the recovery is expected to be a multi-year process. Reservoir levels are expected to be sufficient to meet forecast peak demands and daily energy demands for the summer period. Several hydro facilities in the Region are continuing major rehabilitation such as rewinding of generators, turbine replacements, switchyard work, and dam repairs, but the outages are being coordinated so reliability and contractual commitments will not be impacted. See the subregion reports for further details.

Operational planning studies where needed are discussed in detail in the subregion reports of the SERC report.

In general, there are no operational changes required of utilities in the SERC Region to implement the integration of variable generation. Most of SERC is in the lowest wind resource area of the country. One operational change to note is that for the utilities in the Gateway subregion who are members of Midwest ISO, on January 6, 2009 the Midwest ISO began operation as a single Balancing Authority in conjunction with the commencement of the Midwest ISO Ancillary Services Market.

There are no anticipated unusual operating conditions that could impact the reliability of the utilities in the SERC Region for the coming 2009 summer. Results of a drought impact study performed in 2008 remain useful in those portions of the system still recovering from drought.

Reliability Assessment Analysis

In aggregate, the utilities in the SERC Region expect just 2 MW of Planned capacity to be placed in service between January 1 and June 1, 2009. The projected 2009 summer reserve margin for SERC is 23.9 percent indicating capacity resources in SERC are expected to be adequate to supply the projected firm summer demand. The reserve margin projected for 2008 summer was 19.0 percent. To understand the extent of generation development in the Region, it is instructive to examine the amount of generation connected to the transmission system for the upcoming summer season. 264,300 MW of generating capability is expected to be connected in the Region.

SERC does not implement a regional or subregional planning reserve requirement. As described in more detail within the subregion reports, many utilities adhere to their respective state commissions' regulations or internal business practices regarding maintaining adequate resources. For example, a target margin is implemented by regulatory authorities in the state of Georgia, where the regulation is only applicable to the investor-owned utilities in that state. Based on a recent review of resource adequacy assessment practices, many utilities in the SERC Region use a probabilistic generation and load model to determine that adequate resources are available and deliverable to the load.

Within the SERC Region there are generally three methods used for resource adequacy assessment among the major utilities:

- Deterministic - A stated, deterministic minimum-reserve guideline: In some cases the reserve guideline is derived explicitly from other measures, such as operating-reserve requirements, load-forecast uncertainty, or largest single contingency.
- Probabilistic - A stated probabilistic guideline: Is translated into an equivalent minimum-reserve guideline for use in long-range planning studies.
- Economic - An economically optimized probabilistic guideline: Is translated into an equivalent minimum-reserve guideline.

Among those utilities performing probabilistic reliability analysis, there are two general categories of models being used. Most of these models are in-house held as proprietary. They are:

- Conventional convolution-based or Monte Carlo models that treat hours independently, dealing with energy-limited resources and other time-constrained capacity resources mainly through application of external assumptions.
- Chronological Monte Carlo applications that internally model energy-limited resources explicitly to estimate their use and the impact of energy limitations on reliability

On March 25, 2009, the SERC Board Executive Committee authorized the performance of a Region-wide resource adequacy study. Results are expected in 2010.

External resource dependence is discussed in the subregional reports. In general, the utilities within SERC as a whole are not dependent on external resources to meet load obligations to any significant extent. There is no reliance on external sources for emergency imports. A number of SERC utilities have entered into reserve sharing groups. Any cross-regional sharing has been coordinated for reporting purposes to avoid double counting of resources.

Demand response programs vary widely in design and penetration levels. Most utilities report some form of demand response program. Please refer to each subregion report for details.

Of the 16 states in the SERC Region, five have renewable portfolio standards at the state level. They are: North Carolina, Virginia, Texas, Illinois and Missouri. At the time of this report, a negligible amount of renewable resources has been identified within the SERC Region. There are no specific changes in planning or operations related to the inclusion of renewable or variable generation projects for this coming summer.

There are no significant unit retirements planned within the SERC Region and there are no reliability concerns as a result. The SERC Generation Survey reveals that no generation will be retired before 2009 summer.

The question of electricity deliverability is handled by each planning authority (e.g., MISO and PJM in those portions of SERC covered by these RTOs) or other regional transmission planning groups. Studies performed by the SERC study groups and committees mentioned in this report collectively conclude that the SERC Region as a whole meets the requirements of NERC Standards TPL 001-004

Transmission deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak. The transmission system within SERC has been planned, designed, and is operated such that the utilities' generating resources with firm contracts to serve load are not constrained. Network customers may elect to receive energy from external resources by utilizing available transmission capacity. To the extent that firm capacity is obtained, the system is planned and operated in accordance with NERC Reliability Standards to meet projected customer demands and provide contracted transmission services. Studies have been developed to ensure proper planning has been performed to ensure the reliability of the

SERC Region. The Region relies on the SERC Near-term Study Group (NTSG), Long-term Study Group (LTSG), Dynamic Study Group (DSG) and Short Circuit Database Working Group (SCDWG) to coordinate its transmission transfer capabilities to ensure that import transfer capabilities and external resources for import are adequate for projected winter peaks. Coordinated studies with neighboring regions and SERC subregions through the Eastern Interconnection Reliability Assessment Group-Multi-regional Modeling Working Group (ERAG-MMWG) indicate that transmission transfer capability will be adequate on all interfaces to support reliable operations for the summer assessment period. These processes and studies are discussed in more detail in the subregion reports.

The projected 2009 summer capacity mix reported by SERC utilities is well diversified at approximately 37.46 percent coal, 13.95 percent nuclear, 8.49 percent hydro/pumped storage, 38.33 percent gas and/or oil, and 1.77 percent for purchases and miscellaneous other capacity. Generation with coal, nuclear and hydro fuels continues to lead the regional fuel mix accounting for roughly 59.90 percent of net operable capacity. Sufficient inventories (including access to salt-dome natural gas storage), fuel-switching capabilities, alternate fuel delivery routes and suppliers, and emergency fuel delivery contracts are some of the important measures used by SERC utilities to reduce reliability risks due to fuel supply issues.

Fuel supplies are projected by all SERC utilities to be adequate for this summer. This topic is covered in detail in the subregion reports of this assessment. Although fuel deliverability problems are possible for limited periods of time due to weather extremes such as flooding, rail, pipeline and other transportation system disruptions, assessments indicate that this should not have a negative impact on reliability. The immediate impact will likely be economic as some production is shifted to other fuels. Secondary impacts could involve changes in emission levels and increased deliveries from alternate fuel suppliers. Coupled with economic conditions, which have reduced pressure on rail and pipe lines, SERC anticipates that no fuel deliverability constraints would significantly impact the availability of capacity resources.

Utilities in the SERC Region with large amounts of gas-fired generation connected to their systems have conducted electric-gas interdependency studies in past years. The studies simulated pipeline outages for near and long-term study periods as well as both summer and winter forecasted peak conditions. Also included, for each of the major pipelines was an analysis of the expected sequence of events for the pipeline contingency, replacing the lost generating capacity, and providing an assessment of electrical transmission system adequacy under the resulting conditions.

Total dual fuel capabilities within the Region are 36,882 MW or 15.16 percent of capacity. Dual fuel units are tested to ensure their availability and that back-up fuel supplies are adequately maintained and positioned for immediate availability. Some generating units have made provisions to switch between two different natural-gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources further reduces the risk. Current assessments reveal that the fuel supply infrastructure and fuel inventories for the summer period are adequate even considering possible impacts due to weather extremes.

We have already identified the drought conditions of recent years as a special operating condition. The drought has moderated significantly in most parts of the SERC Region and for the 2009 summer load-serving obligations we expect no impact on either thermal or hydro production based on prior studies of extreme drought conditions.

Individual companies within SERC have dynamic reserve criteria and dynamics; small signal and voltage issues and studies are discussed in the subregion reports. There are no issues in this area on a SERC-wide basis.

The processes for dynamics and voltage criteria rest with each utility in the SERC Region. There is no broad criteria, rather each utility involved in planning has clear criteria for voltage and transient performance. See each subregion report for information.

For SERC as a whole the influence of extreme weather at the 90th percentile peak temperature relates to an extreme weather peak of about 6 percent higher than the regular forecast for the Region. An extreme peak for 2009 summer equates to 213,446 MW of peak demand for the Region. The reserve margin for this scenario is estimated to be 17.4 percent, which, although reduced from normal margins, is an adequate level for these conditions. This analysis assumes the load response to temperatures in this extreme range is linear. However, historical evidence indicates that at some point saturation occurs as temperatures rise, so the reserve margin could be higher. The utilities within SERC as a whole are not expected to have any difficulty serving customers in a 90/10 outcome relative to the next summer season. Some subregion reports provide analysis at a 5 percent level.

There are no identified project cancellations due exclusively to the economic slowdown. This is the first construction/planning cycle where the impacts of the economic slowdown are being experienced. Reduction in load forecasts, if they persist, may result in project cancellations in the future.

The foregoing study process and its products establish deliverability between the subregions and to the outside regions. These include reports on steady state power flow studies, dynamics/stability studies[77] and short-circuit studies. The Annual Report of the SERC Reliability Review Subcommittee (RRS) to the SERC Engineering Committee (EC) summarizes the work of the SERC subcommittees relative to the transmission and generation adequacy and provides the overview of the state of the systems within the SERC Region.[78]

[77] Small signal damping is considered in the context of stability studies by some SERC subregions

[78] Because it is considered CEII, the SERC RRS Annual Report to the Engineering Committee is available only upon request through the SERC website at www.serc1.org.

Central

Demand

Projected total internal demand for utilities in the Central subregion for the 2009 summer season is 42,733 MW. This is 1,133 MW (2.7 percent) lower than the forecast 2008 summer peak demand of 43,866 MW. The projected total internal demand for 2009 is 882 MW, (2.1 percent) higher than the actual 2008 summer peak of 41,851 MW, which was lower than expected. The lower than expected summer peak in 2008 was due to lower temperatures and the effects of the economic slowdown on industrial demand. The change in demand from prior forecasts for 2009 also reflects the effects of the economic slowdown in lowering growth in customer and energy use.

The 2009 summer demand forecast is based on normal weather conditions and economic data for the subregion population, expected demographics for the area, employment, energy exports, and gross regional product increases and decreases. Economic data from the national level is also considered. To assess variability, utilities within the subregion use forecasts assuming normal weather, and then develop models for milder and historical peaks, and demand models to predict variance. For the majority of the load in the subregion, peak information is developed as a coincident value for the subregion-wide model, and non-coincident values for each distribution delivery point.

As with other subregions in SERC, strong emphasis is placed on energy efficiency and consideration of renewables. During 2008, TVA announced a program with ambitious goals for efficiency and DSM. As part of the Region's energy efficiency program implementation, energy audits, low-income assistance, HVAC system improvements, lighting and verification/measurement groups are in place. Residential programs currently focus on building-shell thermal efficiency, high-efficiency heat pumps, new manufactured homes, and self-administered paper and electronic online energy audits. In the future, programs will include third-party onsite home energy audits. Commercial/industrial/direct-served industry (DSI) programs will focus on HVAC and lighting efficiencies with future program expansions to include pumps, motors, and other electrical intensive equipment. Some entities have reported that programs must pass both a quantitative (via DSM Portfolio Pro) and a qualitative screening analysis that covers customer acceptance, reliability and cost effectiveness.

The primary source of demand response in the Central subregion utilities is the Direct Load Control (DLC) program and the interruptible product portfolio, which includes companies that have contractually agreed to reduce their loads within 60 minutes of a request. The estimate used in operational planning takes into account the amount of load available and is not just a sum of all load under contract. Control devices are being installed on air conditioning units and water heaters in residences. The goal is to have 50,000 switches by 2013.

Generation

Utilities in the Central subregion expect to have the following capacity on peak. This capacity is expected to help meet demand during this time period. For 2009 summer we expect 50,754 MW of existing certain generation, 3,500 MW of hydro, 73 MW of biomass and 1,643 MW of existing other generation.

The wind resource in the Central subregion is generally unsuitable for large-scale wind generation. 29 MW of wind turbines are installed at Buffalo Mountain but are not reported in the above generation totals as they are not considered as capacity.

To address variable capacity calculations, subregional utilities either have no variable capacity or do not consider them toward capacity requirements. For reliability analysis/reserve margin calculations, entities within this subregion may use a request for proposal (RFP) system for forward-capacity markets or use firm contract purchases (both generation and transmission) toward firm capacity. Overall, the utilities in the subregion do not depend on outside purchases or transfers from other regions or subregions to meet their demand requirements.

Capacity Transactions on Peak

Central subregion utilities have reported the following imports and exports for the upcoming 2009 summer season. The majority of these exports/imports are backed by firm contracts and none were reported to be associated with liquidated damages contracts (LDC). These reports have been included in the aggregate reserve margin for utilities in the subregion.

Table SERC - 3: Central Subregional Imports/Exports

Transaction Type	2009
Firm Imports (External Subregion)	684 MW
Firm Exports (External Subregion)	793 MW
Expected Imports (External Subregion)	0 MW
Expected Exports (External Subregion)	0 MW
Provisional Imports (External Subregion)	0 MW
Provisional Exports (External Subregion)	0 MW

Transmission

The following table shows bulk power system transmission categorized as under construction, planned, or conceptual that is expected to be in-service for the upcoming 2009 summer season since 2008.

Table SERC - 4: Central Expected Under-Construction, Planned, Conceptual Transmission

Transmission Project Name	Transmission Type	In-Service Date(s)	Operating Voltage (kV)	Concerns in meeting	Reliability Issues with In-Service Date Delay?	Mitigation Plans to Address Delay
Trimble County - Ghent-Speed Line	Under Construction	Jun-09	345	NA	NA	NA
Rutherford - Almaville	Planned	Jul-09	161	No	NA	NA
Tilton - Resaca	Planned	Sep-09	230	No	NA	NA

No constraints have been identified that could significantly impact reliability for 2009 summer. System conditions may at times dictate local area generation re-dispatch to alleviate anticipated next contingency overloads. NERC TLR procedures will be applied in scenarios that are not easily remedied by a local re-dispatch. There are no significant projected changes since the 2008 assessment. No new plans to install significant substation equipment have been identified by subregional entities.

Operational Issues
No major generating unit outages, generation additions, environmental/regulatory restrictions or temporary operating measures are expected to affect the reliability of the Central subregion this summer.

Some entities within this subregion are still experiencing drought conditions, which can result in low water levels or limiting water temperatures. These conditions are considered in capacity alternative planning (for example purchases from the short- term markets). Lower water levels have not impacted fuel (coal barge) deliveries.

The total nameplate rating for all units in the U.S. Army Corps of Engineers Nashville District is 914 MW. Currently there exists a concern that has prompted the Corps to lower certain reservoir elevations and lowered water levels at the Wolf Creek dam continue to limit the amount of capacity available from SEPA. No mechanical deratings have been declared by the Corps, but it is unlikely the area will have sufficient inflows to support the capacity throughout the summer months. As a result, SEPA customers have collectively reduced the total schedule to 554 MW for the summer season.

Studies have been done based on projected normal peak conditions. No unique problems have been observed. Some units are undergoing maintenance; however, reliability should not be affected. Monthly, weekly, and daily operational planning efforts take into consideration demand and unit availability. This helps to address any inadequacies and mitigate their risks. No operational changes are expected in this subregion from the integration of variable resources. No unusual operating conditions are anticipated for this summer.

Resource Assessment Analysis
Projected summer peak reserve margin for the utilities in the subregion, as reported in January 2009, is expected to be 23.9 percent compared to 31.4 percent for 2008.

The reserve margin analysis in the company-integrated resource plans incorporates sensitivities on load unit availability, purchase power availability, unserved energy cost and varying reserve margin levels. There is no mandate or target reserve margin for the subregion. Monthly and long-term resource planning efforts take into consideration demand and unit availability. If resource inadequacies cause the reserves to be reduced below the desired level, companies within the subregion can make use of purchases from the short-term markets in the near-term and various ownership options in the long-term, as necessary. Several utilities within the Central subregion are members of the Midwest Contingency Reserve Sharing Group (MCRSG), which includes MISO and ten other Balancing Authorities in SERC and MRO. The MCRSG is intended to provide immediate response to contingencies enabling the group to comply with the DCS standard.

Utilities within the subregion are not relying on short-term outside purchases or transfers from other regions or subregions to meet demand requirements. Options to meet long-term demand needs may include building capacity, utilizing existing capacity, expanding current capacity or contracting for capacity.

Many Central subregion utilities have interruptible and direct load controls as demand response programs considered as a resource. Companies have control over these programs and sometimes use them for load reduction, which therefore impacts reserves carried for the system.

No generating unit retirements are planned for the upcoming summer season that could have significant impact on reliability. There are no renewable portfolio standards imposed by the states in this subregion.

In order to ensure fuel delivery, the practice of having a diverse portfolio of suppliers, including the purchase of high-sulfur coal from Northern and Central Appalachia (West Virginia, East Kentucky), Ohio and the Illinois Basin (West Kentucky, Indiana, Illinois) is common within the subregion. Fuels Departments typically monitor supply conditions on a daily basis through review of receipts and coal burns and interact daily with both coal and transportation suppliers to review situations and foreseeable interruptions. Any identifiable interruptions are assessed with regard to current and desired inventory levels. By purchasing from different regions, coal is expected to move upstream and downstream to various plants. Some plants have the ability to re-route deliveries between them. Some stations having coal delivered by rail can also use trucks to supplement deliveries. Utilities have reported that they maintain fuel reserve targets greater than 30 days of on-site coal inventory. Fuel supplies are adequate and readily available for the upcoming summer. Multiple contracts are in place for local coal from area mines.

The Central subregion experienced a severe drought through 2008, which has continued into 2009. Repair work on the Wolf Creek Dam is likely to continue for several more years. Below-average rainfall is expected for the upcoming season; however, reservoir levels should remain sufficient for current operation. Hydro operations are constantly monitored and evaluated for potential changes and mitigation plans are formed to minimize any threats to reliability. While the continuing drought and dam repairs will affect hydro energy and capacity and cause some thermal de-rating, no problems are foreseen in meeting normal reserve margins and maintaining reliability.

Utilities within the subregion rely on quarterly OASIS studies and participate in SERC study groups and ERAG inter-regional studies. For example, the SERC NTSG assesses transfer capability issues with neighboring systems. The SERC and ERAG seasonal studies for projected 2009 summer peak conditions are in progress at the time of this filing. The coordinated study results are expected to be published in reports by early to mid-May. These studies typically assess non-simultaneous transfer capability with selected parallel transfer analysis to gauge interface sensitivities and do not recognize transmission or generation constraints in systems external to the Region.

Companies within the subregion maintain individual criteria to address any problems with stability issues. Recent stability studies identified no stability issues that could impact the system reliability during the 2009 summer season. Criteria for dynamic reactive requirements are addressed on an individual company basis. Utilities employ study methodologies designed to assess dynamic reactive margins. Programs such as Reactive Monitoring Systems give operators an indication of reactive reserves within defined zones on the system.

Voltage stability margins are also upheld by utilities on an individual basis. Some utilities follow the procedure of making sure that the steady-state operating point be at least 5 percent below the voltage collapse point at all times to maintain voltage stability. Studies are performed on peak cases to verify system stability margins. Other utilities follow guidelines to ensure that voltage stability will be maintained via Q-V analysis.

Planning studies for the NERC Reliability Standards TPL-001, TPL-002, TPL-003, and TPL-004 have been performed or are currently being performed at the time of this report. For the studies that have been performed, no issues have been identified for TPL-001 and TPL-002 for 2009 summer conditions under the assumed dispatch and transfer conditions. The studies for TPL-003 have identified some potential local issues that may necessitate generation re-dispatch, transmission switching, and/or load shedding. Studies for TPL-004 have been performed and the consequences assessed. No widespread cascading is expected. Generation resource deliverability is required to be firm. No separate deliverability studies are performed because the requirement is integral to the annual transmission assessment studies.

No impacts on reliability resulting from the current economic conditions have been reported by utilities in the Central subregion for the upcoming summer season.

Delta

Demand

Projected total internal demand of the utilities in the Delta subregion for the 2009 summer season is forecast to be 27,865 MW based on normal weather conditions. This forecast is 575 MW (2.0 percent) lower than the forecast 2008 summer peak demand of 28,440 MW and is 64 MW (0.2 percent) lower than the actual 2008 summer peak demand of 27,929 MW.

The year-over-year decline primarily reflects the anticipated impacts of increased energy efficiency and conservation, reductions in wholesale load, and the impact of the economic recession. The 2009 forecast is based on a new forecast study, which produced new econometrically based forecasts of commercial/industrial load, future economic/demographic conditions and historical data. Distribution cooperative personnel assess the likelihood of these potential new loads and a probability-adjusted load is incorporated into the cooperative load forecast.

Utilities within the Delta subregion reported that beginning in 2008 certain companies started offering energy efficiency programs to distribution cooperatives. The programs offered were home energy audits, CFL lighting, ENERGY STAR-rated washing machines and dishwashers, and ENERGY STAR-rated heat pumps and air conditioners. These programs are offered on a voluntary basis. Utilities plan to offer these types of programs as long as they are determined to be cost-effective. In 2008 the Measurement and Verification (M&V) program was started to measure energy savings and costs for each of the energy efficiency programs. Information from this M&V program will be used to fine tune energy efficiency programs and to determine each program's cost effectiveness. The current forecast includes energy efficiency programs that have received regulatory approval and have incorporated into the sales and load forecasts.

DSM programs among the utilities in the subregion include interruptible load programs for larger customers and a range of conservation/load management programs for all customer segments. There are no significant changes in the amount and availability of load management and interruptible demand since last year.

Load scenarios for outage planning purposes are developed regularly to address variability issues in demand. These load scenarios include load forecasts based on high and low scenarios for energy sales and scenarios for alternative capacity factors. Load scenarios for load flow analyses in transmission planning are also developed and posted to OASIS. Some of these scenarios developed within the subregion were reported to be based on an assumption of extreme weather, which was more severe than the expected peaking conditions but less severe than the most severe conditions found in the historical records. Special analyses are performed to examine expected peak loads associated with cold fronts, ice storms, hurricanes, and heat waves. These analyses are performed on an ad-hoc basis and may be conducted for various parts of the Delta subregion.

Generation

Companies within the Delta subregion expect to have the following capacity on peak to help meet demand during this time period: There are 38,196 MW of Existing Certain resources in the subregion including 64 MW of hydro. There are 2,390 MW of Existing Other resources in the subregion. There are 2,100 MW of energy-only facilities in the subregion. 1,953 MW of the existing resources are reported as inoperable.

Resources are evaluated based on capability to meet required reliability requirements and economics. Future planned capacity additions are built into company portfolios with variable capacity and not counted as capacity to meet Reliability Standards.

Capacity Transactions on Peak

Delta subregion utilities expect the following imports and exports for the upcoming 2009 summer season. These imports and exports have been accounted for in the reserve margin calculations for the subregion. The subregion is dependent on certain imports, transfers, or contracts to meet the demands of its load. All contracts for these imports/exports are considered backed by firm transmission and are tied to specified generators.

Table SERC - 5: Central Transformer Additions

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
J.K. Smith #2	345	230	6/1/2009	Addition - Under Construction: Install 2nd J.K. Smith 345/138 kV autotransformer. Low-side voltage is 138 kV.

Transmission

The following table shows bulk power system transmission categorized as under construction, planned or conceptual that is expected to be in-service for the upcoming 2009 summer season since 2008.

Table SERC - 6: Delta Subregional Imports/Exports	
Transaction Type	**Summer 2009**
Firm Imports (External Subregion)	2, 222 MW
Firm Exports (External Subregion)	1,215 MW
Expected Imports (External Subregion)	0 MW
Expected Exports (External Subregion)	0 MW
Provisional Imports (External Subregion)	0 MW
Provisional Exports (External Subregion)	0 MW

Table SERC - 7: Delta Expected Under-construction, Planned, Conceptual Transmission

Transmission Project Name	Transmission Type (Under Construction, Planned, or Conceptual)	In-Service Date(s)	Operating Voltage (kV)	Concerns in meeting In-Service Date?	Reliability Issues with In-Service Date Delay? (yes/no)	Mitigation Plans to Address Delay
Gobbler Knob - Thayer South	In-service	12/01/08	161	No	No	N/A
Battlefield - Clever	In-service	04/01/08	161	No	No	N/A
No projects required for the assessment period (summer 2009)						

Table SERC - 8: Delta Transformer Additions

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
No projects required for the assessment period (summer 2009)				

No transmission constraints are expected to significantly impact bulk system reliability for the upcoming summer peak season. Some utilities are expecting to use static VAR compensation (SVC) devices in order to provide reactive power support and maintain voltage stability. Series compensation has been installed on two key transmission lines on the system in order to regulate power flows. Utilities plan to continue to employ and research these technologies in order to improve and maintain bulk system reliability.

Operational Issues

No reliability concerns are anticipated for the upcoming peak season as a result of operational issues. There are no major generating unit outages or transmission facility outages planned which would impact bulk system reliability for the 2009 summer season. There are also no local environmental, regulatory restrictions or unusual operating conditions expected that might impact reliability.

Resource and transmission planning studies are commonly used within the subregion to study unique conditions on the system. There are no significant changes from last year's assessment; however, if expected resources are unavailable, alternate resources will be obtained by the full requirements supplier. While some entities anticipate extreme hot weather conditions to reduce generator capability, no expected operational problems were cited. The Balancing Authority has a full requirements contract to ensure resources are available at the time of system peak.

Hydro conditions are anticipated to be normal and sufficient to support generation to meet demand in combination with capacity purchases. Low river levels at the Mississippi New Madrid gauge can impact the capacity of one plant within the subregion; however, a mitigation plan has been developed and was used successfully in the past. The plan involves mobile barges with additional pumping capacity to ensure adequate flow of cooling water. The steam host supplies the water, but there are concerns about depleting the aquifer as the steam host is a large user of water resources. The local farmers and the steam host have agreed to evaluate other water sources such as the Arkansas River rather than rely on aquifer sources. A study has already been performed to evaluate and mitigate the situation.

Reliability Assessment Analysis

Delta subregion utilities projected an aggregate 44.3 percent reserve margin in the subregion as compared to 13.1 percent last year. This is largely due to more complete reporting utilizing NERC's new capacity definitions for 2009, which seems to have resolved prior concerns regarding generation adequacy. Generating capacity for the upcoming season is expected to be adequate to meet demand for the upcoming summer season. There are no required state mandated reserve margins for the subregion. Many utilities base their reserve margins on NERC guidelines to maintain a reserve margin greater than 15 percent. Some utilities in the subregion base their target reserve margins based on a LOLE of 0.1 day/year.

Various utility resource planning departments in the subregion conduct studies annually (either in-house or through contracts) to assess resource adequacy. Modeling of resources and delivery aspects of the power system is used throughout the subregion in all phases of the study. These studies are used to ensure resources are available at the time of system peak. Some companies have reported that results are approved by the board of directors internally. Subregional transmission planning departments also conduct studies to ensure transfer capability is adequate under various contingency conditions. The Balancing Authority has a full requirements contract to ensure studies are performed, upon request of the supplier, by the transmission provider. These studies evaluate the availability of firm transmission from resources. The resources for the upcoming season are internal to the SERC Region and the Delta subregion. The amount of external resources outside the region within Delta was 1,262 MW and 1,215 MW outside the subregion for the upcoming season. These resources were considered to meet the reference margin level for last summer and for the upcoming summer.

Although some Delta subregion utilities participate in the Southwest Power Pool (SPP) Reserve Sharing Group, the subregion is not dependent on outside resources to meet its demand requirements. Utilities typically depend on transfers from other group participants located within the SPP Reserve Sharing Group.

The majority of the utilities within the subregion have no demand response programs. However, those utilities that do have these programs reported that they are treated as a load modifier in resource adequacy assessment. The effects of demand response are incorporated into the load forecast, which is treated stochastically. Renewable Portfolio Standards (RPS) and variable renewable resources are currently not explicitly considered in entity resource adequacy assessments. No changes in planning approaches have occurred since last year, and no changes are expected for the upcoming summer season.

No unit retirements that could affect reliability are expected to occur for the upcoming season. To address generation deliverability, many entities only rely on resources in their capacity plans that are qualified as firm network resources. Utilities in this subregion address deliverability by conducting annual resource planning studies to assess resource adequacy. Transmission planning studies are also performed to ensure transfer capability is adequate under various contingency conditions. These studies are incorporated into the region-wide report performed annually. No deliverability issues are expected based on the availability of transmission and generation expected for the summer.

Fuel supplies are anticipated to be adequate. Coal stockpiles are maintained at 45 or more days. Natural gas contracts are firm. Extreme weather conditions will not affect deliverability of natural gas. Typically, supplies are limited only when there are hurricanes in the Gulf. There is access to local gas storage to offset typical gas curtailments. Many utilities maintain portfolios of firm-fuel resources to ensure adequate fuel supplies to generating facilities during projected peak demand. Those firm-fuel resources include nuclear and coal-fired generation that are relatively unaffected by winter weather events. Various portfolios contain fuel oil inventories located at the dual-fuel generating plants, approximately 10 Bcf of natural gas in storage at a company-owned natural gas storage facility, and short-term purchases of firm natural gas generally supplied from other gas storage facilities and firm gas transportation contracts. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of potentially problematic issues on system reliability. Close relationships are maintained with coal mines, gas pipelines, gas producers and railroads that serve its coal power plants. These close relationships have been beneficial to ensure adequate fuel supplies are on hand to meet load requirements.

Extreme hot weather is expected to increase summer load and decrease summer capability, resulting in lower margins. If adequate resources cannot be procured from the short-term wholesale market, entities will rely on curtailing load, first to non-firm customers and then to firm customers. Although utilities do not consider extreme weather in their resource adequacy measurements, some local distribution cooperatives served by various utilities have arrangements with local media to broadcast peak energy alerts to encourage conservation.

Companies throughout the subregion individually perform studies to assess transient dynamics, voltage and small-signal stability issues for summer conditions in the near-term planning horizons as required by NERC Reliability Standards. For certain areas of the subregion, the 2009 assessment from the study was chosen as a proxy for the near-term evaluation. No critical impacts to the bulk electric power system were identified. While there are no common subregion-wide criteria to address transient dynamics, voltage and small-signal stability issues, some utilities have noted they adhere to voltage schedules and voltage stability margins. In addition, some utilities employ static VAR compensation devices to provide reactive power support and voltage stability. Under-voltage load-shedding (UVLS) programs are also used to maintain voltage stability and protect against bulk electric system cascading events.

While Delta subregion companies do not employ a minimum dynamic reactive requirement or margin, it does employ the following. The voltage stability criterion used by the Delta subregion companies is a voltage stability margin of 5 percent from the nose point (voltage collapse point) load on the P-V curve. Stability studies performed incorporated P-V curve analyses to ensure that this criterion is met on the system. If necessary, stability limits can be imposed on transmission elements in order to meet this criterion.

Under transient conditions, the companies employ the following voltage dip criteria:

1. For the loss of a single transmission or generation component, with or without fault conditions, the voltage dip must not exceed 20 percent for more than 20 cycles at any bus; must not exceed 25 percent at any load bus; and must not exceed 30 percent at any non-load bus; and
2. For the loss of two or more transmission or generation components under three-phase normal-clearing fault conditions, or the loss of one or more components under single-phase delayed-clearing fault conditions, the voltage dip must not exceed 20 percent for more than 40 cycles at any bus; and must not exceed 30 percent at any bus.

To address transfer capability studies, some entities currently use an Available Flowgate Capability (AFC) process to calculate available transfer capability and evaluate transmission service requests in the Day 1 to Month 18 time frame. Because of the inherent granularity and update frequency provided by the AFC process, specific seasonal transfer capabilities are not calculated. Utilities are also currently participating in the SERC NTSG 2009 Summer Reliability Study. This study, which has not yet been finalized, tests transmission transfer capabilities between the Delta subregion and other SERC subregions. The analyses performed to calculate the transfer limits presented in the SERC NTSG 2009 Summer Reliability Study consider all transmission elements identified by participating member companies within SERC. These transfer limits are not based on simultaneous transfer capability.

Utilities within the Delta subregion also participate in the ERAG MRSWS study. In addition to a single FCITC analysis, simultaneous transfers are analyzed. All valid constraints in the Eastern interconnect are analyzed.

To assess compliance with NERC Reliability Standards TPL-001 through TPL-004, utilities within the subregion perform annual assessments on their system on a regular basis. The studies are conducted to address categories A through D of Table 1 from the TPL standards. The reliability issues identified during the assessment are local in nature and are addressed with both planned transmission improvements and the use of footnote B referenced in Table 1 of the TPL standards.

The Delta subregion has identified a dynamic and static reactive power-limited area on the bulk power system. The Western Region of the Entergy Texas, Inc. (ETI) service territory is defined by ETI as a load pocket, which is an area of the system that must be served at least in part by local generation. This load pocket requires importing of power across the bulk electric system in order to meet the real power demand. The reactive power requirements of this load pocket are supplemented by the use of capacitor banks, as well as a static VAR compensator. Several projects, involving both bulk transmission upgrades/additions and generation resource additions, are currently under evaluation in order to increase the real and reactive demand-serving capability of the Western Region.

Although there has been a decrease in new projects and turbine overhaul extensions due to the current economic environment, these decreases are not expected to significantly impact the reliability of generation.

Gateway

Demand

Total internal aggregate demand for the utilities in the Gateway subregion for the 2009 summer season is forecast to be 19,065 MW based on normal weather conditions. This forecast demand is 17 MW (.1 percent) lower than the actual 2008 summer peak demand of 19,082 MW, and is 168 MW (0.9 percent) lower than the forecast 2008 summer peak demand of 19,233 MW. The Gateway subregion's peak is reported on a non-coincident basis and reserves are evaluated for summer conditions. The decrease in 2009 forecast load compared to the 2008 forecast load is due to the lower expectations of economic activity in the subregion. The decrease in 2009 forecast load compared to the 2008 actual peak demand is because the forecast demand is based on normal load and temperature patterns and lower expectations of economic activity. The actual 2008 summer peak load was lower also due to milder than normal temperatures, which resulted in lower peak demand and energy usage. The growth rate from last year's forecast and this year's forecast is expected to be the same throughout the subregion. However, several differences that offset each other to result in the unchanged growth rate. The first year in this year's forecast is lower because of the loss of demand for one year at the largest industrial customer in the subregion. This customer suffered a significant reduction in production capacity resulting from damage to the local area transmission supplies from a severe winter ice storm. It is anticipated that at least 160 MW of that customer's capacity will not be in operation at the time of the 2009 summer peak. The customer load is expected to return to normal operation by next year, providing significant immediate growth.

Some utilities use a price component in their forecasting process. As price would increase, consumption would tend to decrease. Recent history and projected trends indicate continuation of an increasing cost environment due to rising fuel prices, required environmental upgrades, and the potential for a tax on carbon. As a result, higher electric energy prices are expected over the forecast horizon, which tend to have a negative impact on load growth. Additionally, the new federal efficiency standards included in the EISA 2007, primarily the lighting standard, have reduced the forecast demand and growth of residential and commercial loads. The lower growth from these two factors combined with the immediate growth from the return of the outaged industrial customer load results in the same growth rate as last year's forecast. The primary differences between the 2009 forecast and the 2008 actual demand are related to weather and economic conditions. The peak day in 2008 was milder than normal, so the 2009 peak load is expected to be higher than 2008 actual. That weather adjustment is partially offset by lost load.

Gateway utilities have seen a significant deterioration most notably in its industrial load and to a lesser extent, its commercial load because of the poor economic conditions.

Gateway utilities are working with customers to save energy to protect the environment and reduce costs. Energy efficiency information is posted on utility websites to inform and educate consumers to help manage rising energy costs and promote in-state economic development while protecting the environment. Customers can use on-line software to help with purchase decisions regarding lighting, heating and cooling equipment, and electric appliances. Tips on saving energy are also discussed including the use of caulking and insulation as well as turning off computers and other electronic equipment when not in use. Energy efficiency programs are numerous and active throughout the subregion and include energy efficient products and appliances, commercial lighting programs, in-home energy displays, energy efficiency education pilot projects, senior/low-income weatherization programs, heat pump rebates, energy efficient home programs, central air conditioner tune-ups, direct load control/smart appliances and programmable/smart thermostats. Independent third-party contractors have been retained to perform all evaluation, measurement, and verification for the programs after they have been rolled out. The energy efficiency programs are intended to provide a diverse range of options for all customer classes.

The utilities in the Gateway subregion historically have not had large demand response programs because of large capacity reserves and low energy prices. Subregion utilities address demand response by including in their forecast voltage reduction plans that provide several MW of response and behind-the-meter generation that is available from wholesale customers. Programs such as rebates for reducing summer peak demand are currently being investigated to allow customers to purchase special programmable thermostats that will wirelessly cycle customer's air conditioning equipment on and off in short bursts to help curb summer demand. Critical peak pricing control programs and other direct control load management programs are also being investigated for their use on the system. The measurement and verification of these programs will be conducted by an independent evaluator to determine the annual energy savings and portfolio cost-effectiveness. Procedures such as utilizing a contact list for large commercial and industrial customers to request them to reduce demand in addition to public appeals for conservation are also available across the subregion, if needed.

To assess the uncertainty and variability in projected demand, some utilities within the Gateway subregion use regression models, multiple forecast scenario models, and econometric models. Economic assumptions, alternative fuel pricing, electric pricing and historical temperature and weather (pessimistic and optimistic conditions) pattern information are considered individually by each subregion utility.

Generation

Companies within the Gateway subregion expect to have the following aggregate capacity on peak. This capacity is expected to help meet demand during this time period. There is 23,439 MW of Existing Certain generation in the subregion of which 378 MW is hydro. There is 36 MW of existing other generation in the subregion. In addition, 466 MW of the generation in the subregion is inoperable.

The generation resources to serve the retail loads for this summer are predominantly located within the Gateway subregion or in the Midwest ISO (MISO) balancing area. Some utilities have filed Integrated Resource Plans with their local Commissions. Although Gateway subregion utilities have traditionally tried to maintain a planning reserve margin of at least 15 percent, this requirement has been set at a minimum of 12.7 percent based on the LOLE studies performed by the MISO considering a metric of 1 day in 10 years. The Illinois Power Authority has no long-term capacity contract requirements, but follows the planning reserve requirements of the MISO. The MISO queue was polled to determine possible future/conceptual resources.

Presently, Gateway subregion utilities do not include variable capacity plants in their planning reserve margin calculations to cover peak load conditions. However, the MISO Business Practice Manual would allow entities to include wind plants in the resource calculations up to 20 percent of the nameplate capability of the plant.

Capacity Transactions on Peak

The Gateway subregion reported the following imports and exports for the upcoming 2009 summer season. These firm imports and exports have been accounted for in the reserve margin calculations for the subregion. All capacity purchases and sales are on firm transmission within the MISO footprint and direct ties with neighbors. Day-to-day capacity and energy transactions are managed by MISO with security-constrained economic dispatch and LMP. Overall, the subregion is not dependent on outside imports or transfers to meet the demands of its load.

Table SERC - 9: Gateway Subregional Imports/Exports

Transaction Type	Summer 2009
Firm Imports (External Subregion)	861 MW
Firm Exports (External Subregion)	3,637 MW
Expected Imports (External Subregion)	0 MW
Expected Exports (External Subregion)	0 MW
Provisional Imports (External Subregion)	0 MW
Provisional Exports (External Subregion)	0 MW

Transmission

The following table shows new bulk power system transmission additions for 2009 categorized as under construction, planned, or conceptual for the Gateway subregion.

Table SERC - 10: Gateway Expected Under-construction, Planned, Conceptual Transmission						
Transmission Project Name	Transmission Type (Under Construction, Planned, or Conceptual)	In-Service Date(s)	Operating Voltage (kV)	Concerns in meeting In-Service Date? (yes/no)	Reliability Issues with In-Service Date Delay?(yes/no)	Mitigation Plans to Address Delay
Interstate - East Springfield	Under Construction	06/01/09	161	NA	NA	NA
Interstate - San Jose Rail	Under Construction	06/01/09	161	NA	NA	NA
Hamilton Substation - Norris City Substation	Under Construction	07/01/09	345	NA	NA	NA

Table SERC - 11: Gateway Transformer Additions				
Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/ Status
No projects reported for the assessment period				

Although not shown above, most of the major 345 kV transmission additions in the subregion over the next few years are for the connection and delivery of capacity and energy from the 1,650 MW Prairie State Energy Center near Mascoutah, IL. Four transmission lines would be involved in the connection of the facility, while the Baldwin-Rush Island 345 kV line is required for deliverability. Prairie State generating unit #1 is planned for commercial operation in 2011, while unit #2 is planned for completion in 2012. Generation from this plant would be limited if the transmission facilities are delayed.

Though Table 3 includes only new transmission additions, Gateway subregion utilities continually review the capability of their systems and upgrade those limiting facilities as needed to ensure reliability. An extensive amount of reconductoring and equipment replacement, particularly at the 138 kV level, is under construction or planned throughout the subregion. The new interconnection for 2009 at Interstate Substation between CWLP and Ameren facilities will enhance the reliability to the Springfield, IL area and provide transmission outlet capacity for the CWLP Dallman 4 generating unit. The new Hamilton-Norris City 138 kV line will provide for a second 138 kV supply to the SIPC Hamilton 138/69 kV Substation.

The phasor measurement equipment installed at various plants around the subregion is helping to provide post-disturbance data. With time, these installations, in combination with other such phasor-measuring equipment installed elsewhere on the interconnected system, would provide another tool to operations personnel in assessing immediate near-term conditions on the interconnected system. Some utilities are investigating the implementation of a "smart grid" on their systems, and the use of D-FACTS devices on its transmission system for loss reduction, transmission system flow control, and voltage control.

Operational Issues

No reliability problems are anticipated on the Gateway transmission system for this summer. The City of Springfield-CWLP reported that its Dallman generator unit 1, which experienced an explosion that compromised 86 MW, would not be available until fall 2009. The output of the new Dallman unit 4 will be limited in operation this summer. These issues are not expected to impact reliability for the upcoming season. Utilities have not identified any limitations with emissions stipulations, thermal discharge, low water levels, high water temperature or other unusual operating conditions that can have a negative impact on plant capabilities during peak conditions, and no operational changes or concerns are expected to result from distributed resource or integration of variable resources during peak conditions. Operations studies using both 1 in 2 year and 1 in 10 year load forecasts for 2009 summer are in progress. The use of a 90/10 forecast would increase demand by about 5 percent above the 50/50 forecast level. No reliability concerns are expected, similar to the 2008 study results.

Most utilities within the Gateway subregion participate in the MISO market. The availability of large amounts of low-cost base load generation during off-peak load conditions can result in congestion and real-time transmission loading issues. The addition of wind generation in the Gateway subregion and surrounding balancing areas to the north and west may exacerbate the transmission loading concerns in some areas. Generation redispatch may be required at some plants, subject to the security-constrained economic dispatch algorithm of the market, to maintain transmission loadings within ratings. Curtailment of some transactions may also be required. Some base load generation may be forced off during minimum load conditions because of too much generation available to serve the load. Presently, these are not reliability concerns but are market issues.

The Lanesville 345/138 kV transformer has been a constraint to CWLP's import capability due to the Kincaid Special Protection System (SPS). The addition of generation at Dallman described above will provide counter-flow and help to mitigate this constraint when the generation is on.

Reliability Assessment Analysis

Reported resource and load for the Gateway subregion utilities result in a projected summer-peak reserve margin of 9.1 percent, which is less than the MISO resource adequacy requirement. We expect (but have no assurance) that the MISO market mechanisms will fill this gap as the summer progresses. This status attributed to data reporting prior to the identification of all resources committed to serve the retail load in Illinois and the manner in which retail load in Illinois is served. The Illinois Power Agency, which procures capacity resources for the Ameren Illinois Utilities pursuant to Illinois Commerce Commission rules, recently issued an RFP for capacity for the summer of 2009 and beyond. The capacity resources acquired under the RFP will comply with the resource adequacy requirements of the MISO Open Access Transmission and Energy Markets Tariff and may be in place by May 1, 2009. The Midwest ISO Tariff requires that, for the planning year beginning June 1, 2009, each load-serving entity shall demonstrate sufficient capacity resources to meet its forecast load plus its applicable planning reserve margin. The planning reserve margin requirement based on a Loss of Load Expectation metric of 1 day in 10 years is currently 12.7 percent for loads in the Gateway subregion. After completion of the auction, it is expected that by the summer of 2009, adequate resources and reserves would be secured to reliably supply the load in the Gateway subregion. There are no unit retirements projected to occur during the assessment period.

Some utilities reported that the MISO resource adequacy and operational procedures can be found in the MISO Resource Adequacy Business Practice Manual. A 50/50 load uncertainty was used in their latest LOLE analysis. A 90/10 load forecast was not done, however if it were done it is not expected to increase the reserve requirements significantly due to the geographical size and load diversity within MISO. The use of a 90/10 forecast would increase demand by about 5 percent above the 50/50 forecast level for the Gateway subregion. Based on past experience, resources are expected to be adequate for the upcoming peak-demand summer season.

Assuming a 12.7 percent planning reserve margin for a 50/50 load level, the reserve margin for a 90/10 load level would be about 7.7 percent. A small amount of interruptible load may be available for curtailment, along with voltage reduction to reduce the system load. Appeals for voluntary load conservation from the MISO and Gateway utilities would also be available if needed to cover capacity shortages.

Most load-serving entities within this subregion are members of the MISO Contingency Reserve Sharing Group. Entity membership within this group also ensures coverage on any short-term emergency imports, generation tests, demand response, or renewable portfolio procedures (variable resource requirements can be found under the MISO Resource Adequacy Business Practice Manual). Other entities use contracts with various companies to supply them access to renewable energy. The members within MISO are currently studying the impacts of integrating large amounts of variable generating resources on the system. This issue of wind integration has been elevated to a higher level within MISO as the amount of wind generation is expected to increase dramatically in MISO over the next several years.

Fuel supply in the area is not expected to be a problem and policies considering fuel diversity and delivery have been put in place throughout the area to ensure that reliability is not impacted. Several entity policies take into account contracts with surrounding facilities, alternative transportation routes, and alternative fuels. These practices help to ensure balance and flexibility to serve anticipated generation needs.

Hydro conditions are anticipated to be normal and reservoir/river levels are anticipated to be sufficient. These hydro resources represent less than 2 percent of the total capacity in the subregion.

Deliverability is defined, within the subregion, as generation from the generator to any load in the MISO footprint. Deliverability testing studies are performed on an ongoing basis throughout the subregion to ensure that transmission capacity is sufficient to make the generation deliverable. Once the MISO grants Network Resource (fully deliverable) status, it cannot be revoked. Generators that are determined not to be fully deliverable can request that studies be performed to determine what transmission upgrades are required to ensure generator deliverability. Any portion of these units that are undeliverable would be considered as Energy Resources until the transmission upgrades are completed. Full deliverability may be obtained on an interim basis if an approved SPS can be installed to mitigate the transmission constraint. It is up to the Transmission Planners to maintain deliverability through testing. Local Transmission Planners perform studies and upgrade the transmission system as necessary to maintain generator deliverability. Such studies would include those needed to meet the NERC TPL standards and local area planning criteria.

The seasonal assessment performed by the SERC NTSG indicates favorable import capabilities for the Gateway subregion from multiple utilities, with various values up to 2,100 MW. No constraints in the Gateway subregion have been identified that could significantly impact reliability. This assessment is based on non-simultaneous transfer capabilities including the simulation of contingencies only within the SERC Region. Utilities within the Gateway subregion actively participate in SERC study groups to ensure import capabilities are efficient to address sub regional needs. Utilities in the subregion also participate in the ERAG MRSWS seasonal study, which considers additional contingencies and transfer directions from MRO, RFC and SPP. The study results show that the Gateway system is robust with FCITC typically exceeding 2,000 MW on all interfaces. Transmission limitations found are typically not on the Gateway system.

To address transient stability modeling issues, some utilities participate in the SERC DSG. Some Gateway subregion utilities conduct transient stability studies using winter or off-peak load levels, which is a more conservative approach than using summer peak load levels. During 2008, a number of transient stability studies were performed for several plants connected to the Ameren transmission system, with 2008/2009 and 2009/2010 winter system conditions modeled. Similar study work has also been performed for selected plants utilizing summer peak loads for expected 2010 and 2011 conditions. No criteria have been set for voltage or dynamic reactive requirements within this subregion. Some utilities consider a steady state voltage drop greater than 5 percent (pre-contingency - post contingency) as a trigger to determine if further investigation is needed to ensure there are no widespread outages. Voltage stability assessments have been performed for some load centers in Illinois. Some of these areas are subject to voltage collapse for some double-circuit tower outages during peak conditions, but wide spread outages are not expected. Plans to build new transmission lines to mitigate the contingency are proceeding. Public involvement has been solicited to develop possible line routes. Application to the Illinois Commerce Commission for Certificates of Convenience and Necessity to build these new lines are expected to be completed in the fall of 2009. Overall, individual or SERC group studies have not reported any other major issues or concerns within this subregion.

For the 2008 annual assessment of the Ameren transmission system, peak load conditions for 2009 summer and 2013 summer were used as the basis for conducting studies of normal, single contingency, and multiple contingency conditions. A 2009 spring and a 2013 winter model were also used for the near-term assessment. For extreme contingency conditions, no cascading is expected to occur. As an outcome of the results of these annual assessment studies, Corrective Action Plans for the Ameren transmission system, consisting of planned and proposed upgrade work, have been developed over the last several years. Results of the 2008 study work have been used to revise this Corrective Action Plan, which includes projects to relieve thermal, voltage, and local stability concerns. CWLP works with the SERC NTSG and LTSG in performing transmission to comply with NERC TPL Standards.

No negative impacts on reliability are expected for the summer season due to economic conditions.

Southeastern

Demand

Total aggregate internal demand for utilities in the Southeastern subregion for the 2009 summer season is forecast to be 49,504 MW based on normal weather conditions. This is 618 MW (1.2 percent) lower than the forecast 2008 summer peak demand of 50,122 MW and 689 MW (1.4 percent) higher than the actual 2008 summer peak demand of 48,815 MW. Growth rates are predicted to be less than the last year's rate. The slowdown in housing expansion, lower peaks due to slower consumer growth, the size and timing of several projected new large industrial loads and general economic factors are the reason for the lowered growth rate.

Within the subregion various utilities have energy efficiency programs such as residential programs that may include home energy audits, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, energy efficient new home programs, ENERGY STAR appliance promotions, loans or financing options, weatherization, programmable thermostats, and ceiling insulation. Commercial programs include energy audits, lighting programs, and plan review services are available to various customers within this subregion. Some energy efficiency programs are measured by engineering models. A new program, the Conserve101 energy efficiency/conservation program, was also put in place by one utility to educate residential consumers about no-cost/low-cost methods they can use in order to reduce their monthly household electric usage and to provide methods on how to use electricity wisely in their home. These methods are simple to implement, inexpensive and non-intrusive to the consumers' lifestyles. The goal is for each residential consumer to implement these no-cost/low-cost measures in order reduce their monthly electric consumption by at least 101 kWh per month. The potential by-products of the program will include possible demand reductions for the electric cooperative as well as opportunities for utility systems to offer products and services that enhance the Conserve101 energy efficiency programs that are promoted under the umbrella of the at-home energy efficiency program. Energy efficiency utility services programs are designed to ensure long-term viability of the electric cooperative system. These utility services programs were developed as an ongoing customer-oriented focus on retaining and acquiring utility services. The purpose of the current energy-efficiency utility services program continues to be a promotion and price-oriented program. The program is intended to be a system-wide effort, with expected benefits occurring both with the member-owner and with their member-consumers. Expected benefits of this proactive energy efficiency program are lower demand growth, improved load factor, increased customer confidence in member electric cooperatives, and of course, added-value for the customer's energy dollar. These programs are designed to invest rebates and incentives through promotion of energy efficient electric products and services in the following areas/ways: 1) geothermal program, 2) dual-fuel program, 3) manufactured home program, 4) water heaters, and 5) compact fluorescent lighting. Utility systems are required to report monthly and annual rebates and incentives associated with each area of their home energy efficiency program.

Other programs such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits and comfort advantage energy efficient home programs promote reduced energy consumption, supply information and develop energy efficiency presentations for various customers and organizations. Utilities are also beginning to work with the State Energy Division on energy efficiency planning efforts. Training seminars addressing energy efficiency, HVAC sizing, and energy related end-use technologies are also offered to educate customers.

The 2009 summer demand forecast is based on normal weather conditions using normal weather and load growth, and conservative economic scenarios. The subregion has a mix of various demand response programs including interruptible demand, customer curtailing programs, direct load control (irrigation, A/C and water heater controls) and distributed generation to reduce the magnitude of summer peaks. To assess variability, some subregion entities develop forecasts using econometric analysis based on approximately 40-year (normal, extreme and mild) weather, economics and demographics. Others within the subregion use the analysis of historical peaks, reserve margins and demand models to predict variance.

Generation

Utilities within the Southeastern subregion expect to have the following aggregate capacity on peak to help meet demand during this time period. There are 57,153 MW of existing certain and 9,753 MW of Existing, Other resources in the subregion.

For Future and Conceptual capacity resources, entities go through various generation expansion study processes to determine the quantity and type of resources to add to the system in the future. Utilities have reported that reliability analyses are conducted typically for the peak period four years ahead. With the same or greater lead-time, some companies engage processes for self-building or soliciting from the market any capacity resources needed. Load forecasts are reviewed yearly and resource mix analyses are performed to determine the amounts and types of capacity resources required to meet the companies' obligations to serve. By the time the reliability analysis is conducted, those capacity resources have been committed by the companies and have high probability of regulatory approval. Power purchase agreements are also contracted from the market by that time. The resulting inputs to the reliability analyses are known or have very high confidence. Variable capacity is very limited within this subregion and therefore is not commonly included in calculations.

Capacity Transactions on Peak

Southeastern utilities reported the following imports and exports for the upcoming 2009 summer season. The majority of these imports/exports are backed by firm contracts, but none are associated with LDCs. These firm imports and exports have been included in the reserve margin calculations for the subregion. Overall, the subregion is not dependent on outside imports or transfers to meet the demands of its load.

Table SERC - 12: Southeastern Subregional Imports/Exports	
Transaction Type	**Summer 2009**
Firm Imports (External Subregion)	4,130 MW
Firm Exports (External Subregion)	2,435 MW
Non-Firm Imports (External Subregion)	0 MW
Non-Firm Exports (External Subregion)	172 MW
Expected Imports (External Subregion)	0 MW
Expected Exports (External Subregion)	0 MW
Provisional Imports (External Subregion)	0 MW
Provisional Exports (External Subregion)	0 MW

Transmission

The following table shows bulk power system transmission categorized as under construction, planned or conceptual that is expected to be in-service for the upcoming 2009 summer season since 2008.

Table SERC - 13: Southeastern Expected Under-construction, Planned, Conceptual Transmission						
Transmission Project Name	**Transmission Type (Under Construction, Planned, or Conceptual)**	**In-Service Date(s)**	**Operating Voltage (kV)**	**Concerns in meeting In-Service Date? (yes/no)**	**Reliability Issues with In-Service Date Delay? (yes/no)**	**Mitigation Plans to Address Delay[1]**
Calvert SS - Tensaw SS	Under Construction	01/23/09	230	No	No	See note below
Tensaw SS - TK Rolling Mill	Under Construction	03/06/09	230	No	No	See note below
Tensaw SS - TK Rolling Mill	Under Construction	03/06/09	230	No	No	See note below
Tensaw SS - TK EAF	Under Construction	05/08/09	230	No	No	See note below
Tensaw SS - TK EAF	Under Construction	05/08/09	230	No	No	See note below
Tensaw SS - TK EAF	Under Construction	05/08/09	230	No	No	See note below
Black Pond Tap - Black Pond DS	Under Construction	06/01/09	161	No	No	See note below
Bucks SS - Tensaw SS	Under Construction	07/06/09	230	No	No	See note below
Bio - Airline	Under Construction	06/01/09		No	No	See note below
McConnell Road - Woodlore	Under Construction	06/01/09	230	No	No	See note below
Woodlore - Battlefield	Under Construction	06/01/09	230	No	No	See note below
Nebo - New Georgia	Under Construction	06/01/09	115	No	No	See note below
Chevron Cogen - Chevron PRCP	Under Construction	11/11/08	115	No	No	See note below
Bowen - Villa Rica Primary 500 kV line conversion to 230 kV	Under Construction	06/01/09	230	No	No	See note below
Black Pond Tap - Black Pond DS 161 kV line	Under Construction	06/01/09	161	No	No	See note below
Bucks SS - Tensaw SS 230 kV line	Under Construction	07/06/09	230	No	No	See note below

Current economic conditions have resulted in lower load forecasts, which may delay the need for certain pro jects. Re-evaluated need dates m ay push projects out in tim e, but this is not a reliability issue.

Table SERC - 14: Southeastern Transformer Additions				
Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Thomson	500	230	6/2/2010	Addition - Under Construction: New 1344 MVA 500/230 kV transformer @ Thomson/ Under construction

The utilities in the subregion have not identified any anticipated unusual transmission constraints that could significantly impact reliability. Additionally, there are no significant projected changes and reliability concerns since the 2008 assessment. A 230 Mvar SVC was placed in service in 2008 to provide needed dynamic voltage support in the north Georgia area. No other new technologies are planned for the near future that will significantly impact transmission reliability.

There are no new SVCs or FACTS controllers to be placed in service in this subregion in 2009.

Operational Issues

No reliability problems due to additional/temporary or unusual operating measures are anticipated to negatively affect the transmission systems of the Southeastern subregion utilities this summer. Generator maintenance for the units within the Southern Control Area does not normally occur during the summer months. There are no generator unit maintenance outages scheduled for the upcoming summer. In the event a maintenance outage is requested, the outage request would be coordinated with operation planning through system studies. With the current scheduled generator maintenance outages, generation adequacy is maintained in all months and transfer capability is adequate to meet firm commitments. Planned transmission and generation outages are posted on the NERC SDX and updated each day. Fossil generating units in the Southern Control Area have several operating limits related to air and water quality. These limitations are derived from both federal and state regulations. A number of units have unique plant-specific limits on operations and emissions. Some are annual limits while others are seasonal which do not allow the use of fuel oil during these months. These restrictions are continually managed in the daily operation of the system while maintaining system reliability. It has been reported that parts of Georgia have been experiencing level-four drought conditions in as much as 12 percent of the state over the last year; a reduction from almost 50 percent levels in the year preceding that. The Governor of Georgia has directed water withdrawal and drinking water permit holders to reduce monthly average withdrawals by 10 percent. Current water level conditions and long-term weather forecasts indicate low concern for these issues for the 2009 summer season. Utilities within the subregion experienced such events in the summer of 2007 and produced resource adequacy studies. There are currently water level limitations within the Southern Control Area on generator plants located on the Savannah River. These limitations have been included in summer studies and do not pose any reliability impact.

Subregional utilities perform studies of operating conditions for 12-13 months into the future. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and firm transmission commitments for the time period studied, which are updated on a monthly basis. Additional reliability studies are conducted on a 2-day out, next-day out basis and as changing system conditions warrant. The current operational planning studies do not identify any unique or unusual operational problems. Some units are undergoing maintenance over the next 13 months; however, reliability should not be affected.

The Southern Control Area routinely experiences significant loop flows due to transactions external to the Control Area itself. The availability of large amounts of excess generation within the Southeast results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs or market conditions outside the Southern Control Area rather than by loading within the control area. Significant changes in gas pricing dramatically impact dispatch patterns. All transmission constraints identified in current operational planning studies for the 2009 summer can be mitigated through generation adjustments, system reconfiguration or system purchases.

There are no operational changes or concerns regarding distributed resource integration or integration of variable resources.

Reliability Assessment Analysis

The projected reserve margin in the Southeastern subregion is 23.1 percent compared to 24.8 percent last year. Load forecast and term initiation of power purchase contracts are comparable to last year's projections and terms. For one subregion utility, the bulk of capacity resources are either owned fully, jointly owned, or governed by long-term capacity/energy PPAs. The plan continues to rely only minimally upon external resources (150 MW), of which the utility has joint ownership. Reservoirs and reserve margins are expected to be sufficient in 2009. In addition to the resources included in the reserve margin calculation, demand side options are available during peak periods along with large amounts of merchant generation in the subregion. Capacity in the subregion should be adequate to supply forecast demand.

The state of Georgia requires maintaining at least 13.5 percent near-term (< 3 years) and 15 percent long-term (three years or more) reserve margin levels for investor-owned utilities. Recent analyses of load forecasts indicate that expected reserve margins remain well above 15 percent for the next several years, for most utilities in the subregion. Analyses accounts for planned generation additions, retirements, deratings due to environmental control additions, load deviations, weather uncertainties, and forced outages and other factors. Resource adequacy is determined by extensive analysis of costs associated with expected unserved energy, market purchases and new capacity. These costs are balanced to identify a minimum cost point which is the optimum reserve margin level.

The latest resource adequacy studies show that reserve margins for 2009 summer are expected to be within the range of 15 percent to 33 percent for utilities within the subregion. It is not expected to drop below 15 percent. Even though utilities use purchases and reserve sharing agreements, they are not relying on resources from outside the Region or subregion to meet load. Additionally, post-peak assessments are conducted, on an as-needed basis, to evaluate system capability resulting from an extreme peak season. Results indicate that existing and planned resources exceed the target reserve margin. In long-term planning, reserve margin studies typically take into account 39 years of historical weather and associated hydro capacity in order to plan for the variability of resources to meet peak demand. This approach provides enough reserves to account for periods when peak demand is higher than expected. Additionally, studies have been performed to include a 2008 resource adequacy analysis assuming extended drought with gas pipeline failure. Conclusions and recommendations are being developed to address issues identified therein. Weather scenarios are also modeled to account for periods when peak demand is higher than expected. Available territorial generation resources are expected to be sufficient to meet projected demand and to maintain adequate operating reserves.

The amount of external resources (outside the SERC Region but within the Southeastern subregion) was 2,182 MW, while 5 MW was outside the subregion for the upcoming 2009 season. These resources were considered to be able to meet the criteria or target margin levels for last summer and for the upcoming summer.

Most utilities in the subregion do not include demand response effects in their resource adequacy assessments, but those that do consider them include these programs based on their Real time pricing (RTP) categories. RTP load response was reported to be divided into two categories: standard and extreme. Standard RTP by historical observation is that load which is expected to drop at weather-normal peaking-price levels and is deducted from the peak load in the resource adequacy analysis. Extreme RTP is expected to drop at higher pricing levels than expected for the standard RTP and is subdivided into separate blocks, each having an amount and a price trigger determined by analysis. Extreme RTP is included in the resource analysis as a capacity resource. Interruptible load is evaluated to determine its capacity equivalent, based on the contract criteria, relative to the benefit of a combustion turbine. The resulting value is included in the resource analysis as a capacity resource limited by the contract callable terms: hours per day, days per week, and hours per year.

Renewable Portfolio Standards (RPS) are not commonly implemented or mandated within the subregion, but companies are continually evaluating all types of resources including renewable capacity portfolios. Renewable resources are not considered due to little opportunity for variable resources driven by the unavailability of sufficient wind and solar resources. Biomass, in the form of landfill gas and wood waste, has been introduced in limited quantities. Lack of financing appears to be the primary hurdle for RPS developers causing many to cancel projects despite regulatory incentives. Due to the many cancellations, some companies limit RPS project capacity represented in their integrated resource plan to 50 percent of the proposed project amount. Due to the small amount of proposed RPS capacity, their impact to the total capacity of the system is negligible. As the amount increases and operating experience is gained, integrated resource plans and adequacy analysis will be appropriately adjusted to account for forced outage rates, availability, etc. At present there is no significant unit retirements planned. Although some capacity purchase contracts are lapsing, other contracts have been put in place to begin coincident with the lapse.

Generation deliverability is assessed through generation and transfer models in annual firm transmission assessments. These assessments include the internal generation as well as all purchases. Firm transmission service is reserved on OASIS for the emergency purchase through a Capacity Benefit Margin (CBM) reservation. To the extent that firm capacity is obtained, the system is planned and operated to meet projected customer demands and provide contracted firm (non-recallable reserved) transmission services. Firm capacity is not available in excess of ATC values. Additional resource adequacy studies are performed to assess the system impacts resulting from the location of resources within stability-constrained areas of the system. No deliverability issues are anticipated. Utilities have reported that if issues with deliverability associated with new generation surface, these issues will be mitigated by transmission upgrades that will be complete by the time the generation is available for dispatch. The only studies necessary from a resource adequacy perspective are the FRCC import interface analyses showing deliverability of the Intercession City 143 MW in summer and the interface studies showing that the allocated CBM is available. Only limited amounts of external resources are expected to be required for 2009 summer. No transmission constraints have been identified that would impact existing firm transmission service commitments on the transmission system. These existing firm transmission service commitments include CBM reservations on Southeastern subregion utility interfaces with other subregion utilities within SERC. These commitments are used to access capacity assistance from external resources (if needed) during all load periods and are based on simultaneous and non-simultaneous transfer capabilities. External constraints that are identified during the long-term transmission planning process are coordinated with neighboring regions and subregions to determine their impact on existing firm transmission service obligations. No delivery concerns have been identified which significantly impact resource adequacy. One entity's triennial resource adequacy study assesses unit availability based on historical unit forced outage rates over the past five years.

The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak gas demand. Various companies within the subregion have firm transportation diversity, gas storage, firm pipeline capacity, and on-site fuel oil and coal supplies to meet the peak demand. Additionally, some utilities reported that they will be commissioning a new barge unloading system in the spring and should have redundant systems for unloading barge coal in 2009. Many utilities reported that fuel vulnerability is not an expected reliability concern for the summer reporting period. The utilities have a highly diverse fuel mix to supply its demand, including nuclear, PRB coal, eastern coal, natural gas and hydro. Some utilities have implemented fuel storage and coal conservation programs, and various fuel policies to address this concern. Policies have been put in place to ensure that storages are filled well in advance of hurricane season (by June 1 of each year). These tactics help to ensure balance and flexibility to serve anticipated generation needs. Relationships with coal mines, coal suppliers, daily communications with railroads for transportation updates, and ongoing communications with the coal plants and energy suppliers ensures that supplies are adequate and potential problems are communicated well in advance to enable adequate response time.

Hydro conditions are expected to be normal. The subregion has made substantial recovery from drought conditions over the past 12 months, although base-stream flows remain abnormally low in a few areas. Even with improvement, this will result in below-normal hydro output during the summer season. Mitigation plans would include shedding non-firm load and possible market purchases. Even with this reduction, peak season estimated reserve margin would remain well above the target level.

Some of the utilities within the subregion participate in SERC study groups that model interregional transmission transfer capability studies. Transfer capability studies are routinely performed with neighboring companies both within and outside the SERC Region. The most recent study completed is the SERC NTSG 2008/2009 Winter Reliability Study of Projected

Operating Conditions. External constraints that are identified during development of the SERC NTSG case creation and analysis are coordinated with neighboring regions and subregions to determine their impact on Southern Company's existing firm transmission service obligations. Other utilities perform joint studies that first removes from service a critical generating unit, then begins the incremental transfer, and runs a single contingency report for each transfer increment. When bus voltage or branch loading is out of acceptable range the violation is reported and the transfer continues up to a pre-determined desirable transfer level. Operating guides are then developed to ensure acceptable transfer levels are reached. These studies do not recognize transmission or generation constraints in systems external to the Region or subregion. No internal or external transmission constraints that would impact existing firm transmission service commitments have been identified. The SERC LTSG is currently assessing the transmission transfer capability of the interconnected electric transmission systems for the 2019 summer peak season. This study uses assessments of incremental transfer capabilities among the SERC systems. This study also assesses performance as required by NERC Reliability Standards for Transmission System Performance. The final study assessment will be available by the end of the first quarter of 2009.

The Southeastern subregion does not have subregional criteria for dynamics, voltage and small signal stability; however, various utilities within the subregion perform individual studies and maintain individual criteria to address any stability issues. A criterion such as voltage security margins of 5 percent or greater in MW has been put in place within various utility practices. To demonstrate this margin, the powerflow case must be voltage stable for a 5 percent increase in MW load (or interface transfer) over the initial MW load in the area (or interface) under study with planning contingencies applied. Studies are made each year for the upcoming summer and generally for a future year case. The studies did not indicate any issues that would impact reliability in the 2009 summer season. Other utilities use an acceptable voltage range of 0.95 p.u. - 1.05 p.u on their transmission system. During a contingency event the lower limit decreases to 0.92 p.u with the upper limit remaining the same. The acceptable voltage range is maintained on the system by dispatching reactive generating resources and by employing shunt capacitors at various locations on the system. To address dynamic reactive criterion, some utilities follow the practice to have a sufficient amount of generation on-line to ensure that no bus voltage is expected to be subjected to a delayed voltage recovery following the transmission system being subjected to a worst-case, normally cleared fault. Studies of this involve modeling half of the area load as small motor load in the dynamics model. Prior to each summer an operating study is preformed to quantify the impact of generating units in preventing voltage collapse following a worst-case, normally cleared fault. The generators are assigned points, and the system must be operated with a certain number of points on-line depending on current system conditions including the amount of load on-line and the current transmission system configuration. The study is performed over a range of loads from 105 percent of peak summer load down to around 82 percent of peak summer load conditions.

Several Southeastern subregion utilities conduct transmission planning studies annually for both near-term and long-term planning horizons covering all applicable aspects of TPL-001 through TPL-004. These studies evaluate single, multiple, and extreme contingencies, generator outages with a single contingency line outage and bus outages greater than 230 kV as defined in the reliability standard. The collective set of studies cover a 10- year period and several load levels over that period, including summer, hot weather, shoulder, winter, and valley as appropriate. One utility's Extreme Event Study is also performed annually, covering near-term and long-term horizons and multiple load levels. In addition to TPL-003 and TPL-004 events, this study includes infrastructure security contingency events, which exceed NERC Reliability Standards requirements. No major concerns were identified in normal cases and appropriate mitigation plans have been developed for reliability issues identified through these studies.

No negative impacts on reliability are expected to result from the economic conditions in the Southeastern subregion.

VACAR

Demand

The sum of the total internal demands of the utilities in the VACAR subregion for the 2009 summer season is forecast to be 63,568 MW based on normal weather conditions. This is 438 MW (0.7 percent) higher than the forecast 2008 summer peak demand of 63,130 MW and 1,472 MW (2.4 percent) higher than the actual 2008 summer peak demand of 62,096 MW. The economic recession is expected to cause slowed load growth and a significant increase in load management within this subregion. Utilities in the subregion use a variety of methods to predict load. These may include regressing demographics, specific historical weather assumption or the use of a Monte Carlo simulation using 37 years of historical weather from 1971 to 2007. This method uses three weather variables to forecast the summer peak demands. The variables are: (1) the sum of cooling degree hours from 1 p.m. to 5 p.m. on the summer peak day, (2) minimum morning cooling degree hours per hour on the summer peak day and (3) maximum cooling degree hours per hour on the day before the summer peak day. Economic projections can be obtained from Economy.com, an economic consulting firm, and through the development of demand forecasts.

To assess demand variability, some utilities within the subregion use a variety of assumptions to create forecasts. These assumptions are developed using economic models, historical weather (normal and extreme) conditions, energy consumption and demographics. Others assess variability of forecast demand by accounting for reserve margins through continuous evaluation of inputs used in forecasting processes, high and low forecasts, tracking of forecast versus actual, and multiple forecasts per year.

The utilities in the subregion have a variety of programs offered to their customers that support energy efficiency and demand response. Some of the programs are current energy efficiency and demand side management programs that include interruptible capacity, load control curtailing programs, residential air conditioning direct load, energy products loan program, standby generator control, residential time-of-use, demand response programs, Power Manager PowerShare conservation programs, residential ENERGY STAR rates, Good Cents new and improved home program, commercial Good Cents program, thermal storage cooling program, H20 Advantage water heater program, general service and industrial time-of-use, and hourly pricing for incremental load interruptible, etc. These programs are used to reduce the affects of summer peaks and are considered as part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs.

Generation

Companies within the VACAR subregion expect to have the following aggregate capacity on peak. This capacity is expected to help meet demand during this time period. There are 72,413 MW of existing certain generation resources in the subregion of which 174 MW are biomass and 3,880 MW are hydro. There are 2,135 MW of existing other resources. There are 45 MW of existing inoperable resources in the subregion.

In order to identify the process used to select resources for reliability analysis/reserve margin calculations, resource planning departments for utilities within the VACAR area approach both quantitative analysis and considerations to meet customer energy needs in a reliable and economic manner. Quantitative analysis provides insights on future risks and uncertainties associated with fuel prices, load-growth rates, capital and operating costs, and other variables. Qualitative perspectives such as the importance of fuel diversity, the company environmental profile, the stage of technology deployment, and regional economic development are also important factors to consider as long-term decisions regarding new resources. In light of the quantitative issues such as the importance of fuel diversity, environmental profiles, the stage of technology deployment and regional economic development, several entities have developed a strategy to ensure that the company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions. For example, Duke Energy Carolinas reported that it will take the following actions in the next year to apply this goal: Continue to seek regulatory approval of the company's greatly-expanded portfolio of DSM/EE programs and continue ongoing collaborative work to develop and implement additional DSM/EE products and services; continue construction of the 825 MW Cliffside 6 unit with the objective of bringing additional capacity on line by 2012 at the existing Cliffside Steam Station; license and permit new combined-cycle/peaking generation; continue to preserve the option to secure new nuclear-generating capacity; continue the evaluation of market options for traditional and renewable generation and enter into contracts as appropriate and continue to monitor energy-related statutory and regulatory activities.

Capacity Transactions on Peak

Utilities within the VACAR area reported the following imports and exports for the upcoming 2009 summer season. These sales and purchases are external and internal to the Region and subregion and help to ensure resource adequacy for the utilities within the VACAR area. All purchases are backed by firm contracts for both generation and transmission.

Table SERC - 15: VACAR Subregional Imports/Exports

Transaction Type	Summer 2009
Firm Imports (External Subregion)	1,647 MW
Firm Exports (External Subregion)	150 MW
Expected Imports (External Subregion)	0 MW
Expected Exports (External Subregion)	0 MW
Provisional Imports (External Subregion)	0 MW
Provisional Exports (External Subregion)	0 MW

Of these imports/exports, very few are associated with LDC. Some utilities within this subregion report that there are firm contracts associated with the above imports/exports that are backed for both generation and transmission. Utilities vary in having all or none of their generation/transmission under firm contract.

Transmission

Several improvements to transmission facilities of utilities within VACAR have been completed or planned to be completed by the summer of 2009. The following table shows bulk power system transmission categorized as under construction, planned or conceptual that is expected to be in-service for the upcoming 2009 summer season since 2008.

Table SERC - 16: VACAR Expected Under-construction, Planned, Conceptual Transmission

Transmission Project Name	Transmission Type (Under Construction, Planned, or Conceptual)	In-Service Date(s)	Operating Voltage (kV)	Concerns in meeting In-Service Date? (yes/no)	Reliability Issues with In-Service Date Delay?	Mitigation Plans to Address Delay
Clarendon - Rosslyn	Under Construction	04/30/09	230	No	No	None
Bristers - Gainesville	Under Construction	05/31/09	500	No	No	None
Rockingham - Wadesboro Bowman School	Under Construction	06/01/09	230	No	No	None
Nantahala Hydro - Santeetlah and Fontana	Under Construction	07/31/09	161	No	No	None

Table SERC - 17: VACAR Transformer Additions

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/ Status
Dooms	500	230	06/01/09	Addition - Under Construction
Bristers	500	230	05/01/09	Addition - Under Construction
Suffolk 1	500	230	06/01/09	Addition - Under Construction

The 2009 summer transmission constraint studies are still being completed at this time. Preliminary reports show that: Duke-to-PEC transfer capability will decrease from 1,500 MW to 1,100 MW, Entergy-to-PEC transfer capability will decrease from 1,900 MW to 1,600 MW, SOCO-to-PEC transfer capability will decrease from 2,100 MW to 700 MW. These reductions, if found valid, will be addressed through decreased ATC. Otherwise, the majority of the entities within the subregion do not foresee any transmission constraints for the upcoming season. Near-term assessments have not identified any major transmission constraints, and daily studies are performed to ensure adequate import/export transfer capabilities between utilities are available. Projected system performance in the upcoming season is consistent with results identified in previous assessments.

Utilities in the subregion have employed SVC technology in the past and would consider its use again in the future. Other utilities are actively investigating potential application of "smart grid" technology; wind power forecast tools, increased visualization within Dispatch, Transient Stability Analyzer, Generator Performance Monitor, etc.

Operational Issues

For the upcoming summer season, no major outages, additions, or measures are anticipated. Typical planned maintenance/refuel outages are incorporated in the planning process to reliably meet demands. For the upcoming summer season, no special (out of the ordinary) operating measures to mitigate impacts to bulk system reliability due to planned outages or other anticipated conditions have been identified or planned.

No anticipated local environmental or regulatory restrictions that could potentially impact reliability have been identified. To ensure minimum impact to the system, PJM requires Generation Owners to place resources into the "Maximum Emergency Category" if environmental restrictions limit run hours below pre-determined levels. Max Emergency units are the last to be dispatched.

Drought conditions and water levels across the subregion have improved during the past several months. Utilities within the subregion expect full delivery for the peak demand and daily energy requirements from those purchases that include hydro in their portfolios. If low water conditions occur, some entities have a back up supply of water that is provided by local reservoirs, and retired rock quarries. Other utilities are able to manage constraints through off-peak derates, allowing full load operation across peak hours. Plant personnel are exceptionally proactive in anticipating these concerns and addressing them before they are forced to take any units offline. River-flow issues, particularly at Cliffside within the Duke Energy Carolinas system, are managed through coordination of operations with the hydroelectric facilities upstream of that plant so water will be available at Cliffside during peak load hours.

No unusual operating conditions, reliability issues or operational changes resulting from integration of variable resources were reported on the 2009 operational planning studies of the utilities within the subregion.

Reliability Assessment Analysis

The projected aggregate reserve margin of the utilities within the VACAR area is 19.6 percent, compared to 21.3 percent last summer. Capacity in the subregion should be adequate to supply forecast demand. Although some utilities within this subregion adhere to North Carolina Utilities Commission regulations, other utilities within the subregion established individual target margin levels to benchmark margins that will meet its needs for peak demand. Some assumptions used to establish the individual utilities' reserve/target margin criteria or resource adequacy levels are based on historical experience that is sufficient to provide reliable power supplies. Assumptions also may be based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities, procurement of purchased capacity, generating system capability, level of potential DSM activations, scheduled maintenance, environmental retrofit equipment, environmental compliance requirements, purchased power availability, or peak demand transmission capability. Risks that would have negative impacts on reliability are also an important part of the process to establish assumptions. Some of these risks would include deteriorating age of existing facilities on the system, significant amount of renewables, increases in energy efficiency/DSM programs, extended base load capacity lead times (for example coal and nuclear), environmental pressures, and derating of units caused by extreme hot weather/drought conditions. In order to address these concerns, companies continue to monitor these risks in the future and make any necessary adjustments to the reserve margin target in future plans.

Resource adequacy is assessed by forecasted normal/severe weather cases with additional firm capacity (existing, future and outage models included) and forecasted demand plans on a seasonal basis. In addition, forecast of peak demand is made under a variety of both weather and economic conditions as required under RUS 1710 requirements. From this analysis, resources are planned accordingly. This year's studies are expected to show the system to be adequate based on the current forecast, generation and demand side resources.

To address demand response in resource adequacy studies, some utilities have reported that they are provided with energy and cost data forecasted for current and projected DSM programs. These assumptions have been modeled in various programs such as System Optimizer and PROSYM. Sensitivities on DSM energy and cost projections are made to understand the impact of the program's implementation on total system costs and annual reserve margins. Other companies note that demand response is considered a capacity resource. Since additional firm capacity is secured on a seasonal basis to cover a minimum of 50 percent of the difference between the typical and severe demand forecast, demand response capacity resources are rarely dispatched. Some renewable portfolio standards requirements from North Carolina legislation have been taken into account during resource adequacy planning for variable renewable resources by entities within North Carolina. These requirements affect resources in the areas of solar and biomass in particular. Various methods are used to account for variable renewable resources in studies. Some of these methods are use to evaluate all generation resources the same or to count these resources partially for studies. For the methods in which resources are counted partially, these resources are given a reduced capacity contribution for reserve margin based on an estimated hourly energy profile. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. This historic peak period performance is used to determine the individual unit's capacity factor.

Utilities within the VACAR subregion do not depend on outside resources from other regions or subregions to meet emergency imports and reserve sharing requirements. The amount of external resources from outside the SERC Region delivered within VACAR is projected to be 1,647 MW for the upcoming season. These resources were considered necessary to meet the criteria or target margin level for last summer and for the upcoming summer.

No units are expected to retire this upcoming season. For future seasons, Duke Energy reported that it has developed a timeline of expected retirement dates for approximately 500 MW of old-fleet combustion turbine units and 1,000 MW of non-scrubbed coal units. Various factors, such as the investment requirements necessary to support ongoing operation of generation facilities, have an impact on decisions to retire existing generating units. If the North Carolina Utilities Commission determines that the scheduled retirement of any unit identified for retirement pursuant to the plan will have a material adverse impact of the reliability of the electric generating system, Duke is prepared to seek modification of this plan. For planning purposes, the retirement dates are associated with the expected verification of realized energy efficiency load reductions, which is expected to occur earlier than the retirement dates set forth in the air permit.

Generation deliverability is ensured in various ways throughout the subregion. Some utilities perform generator screenings in accordance with NERC TPL standards (under TPL-001 and -002 conditions), while other entities secure sufficient resources and firm transmission to meet its peak load projections. It was noted that some transmission providers conduct interconnection/deliverability studies by modeling network resources that are proposed to be built within their footprint or when proposed resources are brought from other areas. Within the subregion, the term deliverability refers to resources that reach the load within the transmission provider's footprint, even under contingency situations, or based on a criterion for firm transmission to be granted. No concerns were listed as a delivery issue for the upcoming season.

Utilities within the VACAR area have reported that their generation facilities are expected to maintain enough diesel fuel to run the units for an order cycle of fuel. Fuel supply or delivery problems during the projected summer are not anticipated, as coal demand is expected to be somewhat lower in 2009 and general demand for rail capacity is down as well. Coal stockpiles are adequate to meet peak demand and to accommodate short-term supply disruptions. Some unit outages were also reported to be mitigated through exchange agreements or alternative fuel sources.

Utilities within the subregion reported that the drought within the subregion has diminished considerably, but is still considered extreme in upstate South Carolina. Some constraints within hydro operations were experienced from the drought in the past however, coupled with other resources in the portfolio, projected hydro generation and reservoir levels are expected to be adequate to meet both normal and emergency energy demands for 2009 summer. Water levels and temperatures are challenges during most summers. Typically, they are managed through off-peak derating, allowing full load operation across peak hours. Plant personnel are exceptionally proactive in anticipating these conditions and addressing them before units are taken offline. River-flow issues are also managed through coordination of operations of upstream facilities and other drought contingency plans. Reserve margins are well managed and the full deliveries of peak/daily energy demand from those purchases that include hydro in their portfolios are expected.

A 90/10 forecast is not commonly used within this subregion, but those who do use the method reported that it is roughly 5 percent above the expected forecast. Generous reserve margins ensure adequate resources even if forced outages occur during extremely high demand periods. Measures that would be taken if extremely high demand is anticipated include deferral of elective maintenance and surveillance activities at generating stations that do not affect unit availability or capacity, but could pose a trip risk. Demand-side programs could also be used as needed to reduce demand. Forecasts of peak demand are made under a variety of both weather and economic conditions as required.

Some utilities participate in routine reliability, outage, transfer capability, week-ahead, and next-day studies, as well as studies at the company, subregional, and regional levels. The regional-level studies are coordinated and recognize constraints. The 2009 summer transmission constraint studies are still in progress. Preliminary results show an overall reduction in Progress Energy Corporation import capabilities. Based on preliminary findings, the Progress import capabilities have increased or remained constant from last summer's analysis. These import capabilities are not based on simultaneous transfer capability. Several limits in systems external to the Region or subregion involved in the transfers are showing up in the preliminary results. The SERC NTSG 2009 Summer Reliability Study is the regional operating study assessing the upcoming peak season. Results of this study indicate SCPSA's import capability from Southern Company, GTC, TVA, and Entergy is limited to lower levels than 2008 summer. SCPSA import capabilities from Duke, Dominion Virginia, Progress Energy Carolinas, and SCE&G are at comparable or higher levels than last summer. These studies do not address constraints in systems external to the Region; however, constraints external to the SERC Region are evaluated as part of the SERC East-RFC Seasonal Study Group efforts. The normal incremental transfer capability (NITC) for all exports exceeded the tested levels.

Transmission planning practices are used in accordance with NERC TPL-001 through 004 standards. These studies test the system under stressed conditions, and have historically proven adequate to meet variations in operating conditions, forecast demand and generation availability In addition, special transmission assessment studies are conducted as needed to assess unusual operating scenarios (e.g., limitation on generation due to extended drought conditions), and then develop any mitigation procedures that may be needed. No reliability issues have been identified for the 2009 summer season. Some utilities perform an operational peak self-assessment for anticipated and extreme winter/summer conditions as well as perform interregional analysis in conjunction with neighbors to identify potential issues that may arise between areas. No reliability issues are expected. Tests are also done to assess various stability study criterion as well as stressed system scenarios and contingencies. Studies of this type are routinely performed, both internally and through subregional and regional study group efforts. Stability assessments/criteria are performed and produced on an individual company basis within the VACAR area. Some utilities follow practices such as utilizing a reactive power supply operating strategy based on adopted generating station voltage schedules and electric system operating voltages managed through real-time Reactive Area Control Error (RACE) calculations. Through this operating practice, primary support of generator switchyard bus voltage schedules using transmission system reactive resources, dynamic reactive capability of spinning generators may be held in reserve to provide near-instantaneous support in the event of a transmission system disturbance. Other utilities may develop Reactive Transfer Interfaces to ensure sufficient dynamic Mvar reserve in load centers that rely on economic imports to serve load. Day-ahead and real-time Security Analysis ensure sufficient generation is scheduled/committed to control pre-/post-contingency voltages and voltage drop criteria within acceptable predetermined limits. Reactive transfer limits are calculated based on a predetermined back-off margin from the last convergent case. Overall, no stability issues have been identified as impacting reliability during the 2009 summer season.

Operational studies are performed regularly, both internally as well as externally. Coordinated single-transfer capability studies with neighboring utilities are performed quarterly through the SERC NTSG. Projected seasonal import and export capabilities are consistent with those identified in these assessments. Internal operating studies are performed when system conditions warrant. No reliability issues have been identified for the upcoming season.

Although no expected reliability impacts are exp ected to occur this summer season, certain entities h ave reported increas ed ch anges in th e num bers of new que ued projects or queued project withdrawals. No correlation to economic trends has been made.

Region Description

The SERC Region is a summer-peaking Region covering all or portions of 16 central and southeastern states[79] *serving a population of over 60 million. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles. SERC is the Regional Entity for the Region and is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply system. SERC membership includes 63 member-entities consisting of publicly-owned (federal, municipal and cooperative), and investor-owned operations. In the SERC Region there are 30 Balancing Authorities and over 200 Registered Entities under the NERC functional model.*

SERC Reliability Corporation serves as a Regional Entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. The SERC Region is divided geographically into five subregions that are identified as Central, Delta, Gateway, Southeastern, and VACAR. Additional information can be found on the SERC web site (www.serc1.org).

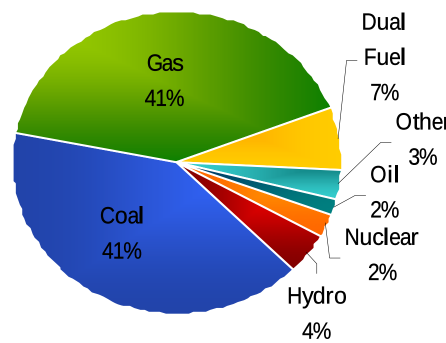
[79] Alabama, Arkansas, Florida, Georgia, Iowa, Illinois, Kentucky, Louisiana, Missouri, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia

SPP

Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	44,342
Direct Control Load Management	33
Contractually Interruptible (Curtailable)	484
Critical Peak-Pricing with Control	35
Load as a Capacity Resource	215
Net Internal Demand	43,575

On-Peak Capacity by Fuel Type



2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	42,827	1.7%
2008 Summer Actual Peak Demand	43,408	0.4%
All-Time Summer Peak Demand	43,482	0.2%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	49,298	13.1%
Deliverable Capacity Resources	49,719	14.1%
Prospective Capacity Resources	55,886	28.3%
NERC Reference Margin Level	-	15.0%

Introduction

Southwest Power Pool (SPP) operates and oversees electric grid in the southwest quadrant of the Eastern Interconnect grid. SPP's footprint includes all or part of 8 states in the US. As of April 1, 2009, the SPP RTO acquired three new tariff and RC members; NPPD, OPPD and LES. The future Regional Entity of the Nebraska entities is still to be determined at this time so MRO will continue to perform Reliability Assessment for these entities until a decision on NERC Delegation Agreement is made.

For the upcoming summer, SPP reports all utilities within the Region expect to meet all customer requirements imposed upon them.

Based on the evaluated contingency events and taking into consideration transmission operating directives, Southwest Power Pool is not expecting any reliability issues for the upcoming summer. The resources available for the Region are adequate to meet the expected peak demand.

Demand

The non-coincident total internal demand forecast for the upcoming summer peak is 44,342 MW, which is 2 percent higher than the 2008 actual summer peak non-coincident total internal demand. The actual 2008 summer demand of 43,408 was 0.3 percent lower than the 43,571 summer forecasted projection for 2008. Last year, SPP experienced a slight decrease in demand from the normal forecast due to mild temperatures in the summer.

Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands are based on 10 year average summer weather, or 50/50 weather. This means that the actual weather on the peak summer day is expected to have a 50 percent likelihood of being hotter and a 50 percent likelihood of being cooler than the weather assumed in deriving the load forecast. SPP does not develop load forecast based on 90/10 weather scenario but has a 13.6 percent reserve margin requirement to address this.

Forecast data is collected from individual reporting members as monthly non-coincident values and then summed up to produce the total forecast for SPP. Each SPP member also provides their demand response programs and then subtracts those values from their load forecasts to report the net load forecast. Based on the SPP member inputs, currently 484 MW of interruptible demand, 33 MW of load management, 35 MW of critical peak pricing and 215 MW of load as a capacity resource are reported.

Generation

SPP expects to have 58,722 MW of total internal capacity for the upcoming summer season. This consists of Existing Certain Capacity of 49,032 MW, Existing Other Capacity of 8,597 MW, Existing Inoperable Capacity of 597 MW, and Future Capacity of 496 MW..

The expected on-peak capacity from the variable generation plant (wind) is 217 MW. The biomass portion that is expected on peak consists of 28 5 MW. The hydro capacity within SPP Region represents a small fraction of the total resources (Approximately 1 percent). SPP monitors potential fuel supply limitations for hydro and gas resources by consulting with its generation owning/controlling members at the beginning of each year. There are no anticipated issues concerning the reservoir levels being sufficient to meet the peak and daily energy demands during the summer season. The SPP Region is experiencing normal rainfall and not expected to experience drought conditions during the summer season that would prevent the Region from meeting their capacity needs.

Capacity Transactions on Peak

SPP has a total of 1,234 MW of projected purchases of which 1,101 MW is firm and 133 MW is firm delivery service from WECC administered under Xcel Energy's OATT. None of the purchase contracts is a Liquidated Damage Contracts.

SPP has a total of 968 MW of firm sales for the 2009 summer by regions external to SPP. None of the sales contracts is a Liquidated Damage Contracts.

SPP members along with some members of the SERC Region have formed a Reserve Sharing Group. The members of this group receive contingency reserve assistance from other SPP Reserve Sharing Group members. The SPP's Operating Reliability Working Group (ORWG) will set the Minimum Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on-line.

Transmission

SPP currently has two projects that are either under construction, or in-service since the end of the 2008 summer. These projects include a 33-mile 230 kV line from Seven Rivers to Potash

Junction to Pecos in Eastern New Mexico and a 40 mile line from Wichita to Reno County in Central Kansas. The details of these projects can be found in the table below.

Table SPP - 1: Transmission Projects				
Transmission Project Name	Voltage (kV)	Length (miles)	In-Service Date	Description/ Status
Potash Junction to Pecos	230	16.3	06/01/09	New 230kV line
Seven Rivers to Pecos	230	18	06/01/09	New 230kV lines
Wichita to Reno County	345	40	12/15/08	In Service

The projects under construction are projected to be in-service before this summer. If there are any delays, SPP will coordinate with transmission owners to ensure a mitigation plan is in place to address any reliability issues. At this time, there are no new transformers or substation projected to be in service before 2009 summer in the SPP Region.

For the rest of the system, SPP is not aware of any transmission constraints that could significantly impact reliability for the upcoming summer. In late 2008, a new 526 MW unit at Hobbs came on-line. This unit is expected to provide reliability support in the Southwestern Public Services (SPS) area in Panhandle Texas for the upcoming summer.

Operational Issues (Known or Emerging)

There are no anticipated unit outages or temporary operating measures foreseen during this summer. Increased amounts of variable resources are anticipated to come online and this may require additional operating directives than in previous seasons. Localized transmission upgrades have been completed or will be completed prior to the summer season, but no major projects will be coming online.

SPP has recently formed Wind Integration Task Force in January 2009. This Task Force is responsible for conducting and reviewing the studies needed to determine the impact of integrating wind generation into the SPP transmission system and energy markets. These impacts should include both planning and operational issues. Additionally, these studies should lead to recommendations for the development of any new tools required for SPP to properly evaluate requests for interconnection of wind generating resources to the SPP transmission system.

The SPP operations staff does not anticipate any environmental or regulatory restrictions that could potentially impact reliability. Because of Flowgate assessment analysis, there are no unusual operating conditions expected for the upcoming summer months.

Due to integration of potential variable resources, additional data collection and situational awareness are put in place to begin assessing regulation and spinning reserve needs.

Reliability Assessment Analysis

Currently, a SPP criterion requires that its members maintain a minimum capacity margin of 12 percent (13.6 percent reserve margin). This is adequate to cover a 90/10 weather scenario. The SPP reserve margin based on certain resources is expected to be 11.6 percent for 2009 summer, which is lower than the 2008 reserve margin of 14.7 percent. On a total potential resources basis, SPP has sustained around a 24.5 percent capacity margin or 34.1 reserve margin. SPP's reserve margin for 2009 is forecasted to be 13.1 percent compared to a forecasted reserve margin of 18 percent for the previous 2008 Summer. The 13.1 percent reserve margin is based on projected data for August 2009 with existing certain and net firm transactions. The reserve margin with prospective capacity resources for the same month is 32 percent.

The total amount of external resources that were used by SPP to meet its criteria for the 2008 and upcoming 2009 summer is 1,234 MW of firm purchases. There are no units being retired in the upcoming summer season that could affect reliability.

SPP is currently performing sensitivity analysis for the Loss-of-Load Expectation and Expected Unserved Energy study. This sensitivity will address the impact of wind penetration in the western part of the grid. The results of these studies are expected in early 2009 summer. Historically, SPP has adhered to a 12 percent regional capacity margin or 13.6 reserve margin to ensure the minimum LOLE of 1 occurrence in 10 years is met. Presently the 12 percent capacity margin or 13.6 reserve margin requirement is checked annually in the EIA-411 reporting as well as through supply adequacy audits of regional members conducted every five years. The last supply adequacy audit was conducted in 2007.

There are no significant deliverability problems expected due to transmission limitation at this time, SPP will continue to closely monitor the issue of deliverability through the Flowgate assessment analysis and thus address any reliability constraints. This analysis validates the list of flowgates that SPP monitors on a short-term basis using various scenario models developed by the SPP Staff. These scenario models reflect all the potential transactions in various directions being granted on SPP system. The results of this study are reviewed and approved by SPP's Transmission Working Group prior to summer.

SPP defines firm deliverability as electric power intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin or reserve margin) and energy. Such power must meet standards of reliability and availability as that delivered to native load customers. Power purchased can be considered to be firm power only if firm transmission service is in place to the load serving member for delivery of such power. SPP does not include financial firm contracts towards this category.

Due to the diverse generation portfolio in SPP, there is no concern of the fuel supply being affected by the extremes of summer weather during peak conditions. If there is to be a fuel shortage, it is communicated to SPP operations staff, in advance, so that they can take the appropriate measures SPP would assess if capacity or reserves would become insufficient due to the unavailable generation. If so, SPP would declare either EEA (Energy Emergency Alert) or OEC (Other Extreme Contingency) and post as needed on the RCIS (Reliability Coordinator Information System).

As a part of the interregional transmission transfer capability study, SPP participates in the ERAG seasonal study group (MRO-RFC-SERC West and SPP) which produces an upcoming summer, and winter operating condition transfer limitation forecast. Simultaneous transfers are also performed as part of this study. The preliminary results of this study will be available in late spring.

SPP develops an annual SPP Transmission Expansion Plan (STEP) with regional group of projects to address system reliability needs for the next 10 years (2009 through 2018). The latest STEP that was approved by SPP Board Of Directors is available on SPP website [80]. During the STEP process, SPP also performs a dynamic stability analysis. The latest dynamic study that was completed for the 2009 operating conditions did not indicate any dynamic stability issues for the SPP Region. In addition, SPP also reviewed the reactive reserve requirements for load pockets within the Region. Currently, SPP does not have specific criteria for maintaining minimum dynamic reactive requirement or transient voltage dip criteria. However, according to reactive requirement study scope, which is completed as a STEP process, each load pocket or constrained area was studied to verify sufficient reactive reserves are available to cover the loss of the largest unit. The annual STEP process conducted by SPP did not indicate dynamic and static reactive power limited areas on the bulk power system.

SPP does not expect any immediate impact on the reliability of the Region due to the current economic conditions.

Other Region-specific issues

SPP continues to see a surge in wind development in the western part (Oklahoma, Texas Panhandle, and Western Kansas) of its system. Because wind–generated capacity is currently such a small fraction, less than 1 percent, of the total SPP capacity, wind farm operational issues are not expected to affect reliability for the upcoming summer. Should the capacity grow to a significant amount, near the reserve margin, additional criteria, such as requiring voltage support, will be added to handle issues native to unstable wind farm operations. SPP has formed a Wind Integration Task Force as described above to address this issue.

Region Description

Southwest Power Pool (SPP) Region covers a geographic area of 370,000 square miles and has members in nine states: Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas. SPP manages transmission in eight of those states. SPP's footprint includes 26 balancing authorities and 47,000 miles of transmission lines. SPP has 54 members that serve over 5 million customers. SPP's membership consists of 12 investor–owned utilities, 11 generation and transmission cooperatives, 11 power marketers, 9 municipal systems, 5 independent power producers, 4 state authorities, and 2 independent transmission companies. Additional information can be found on the SPP Web site. (http://www.spp.org).

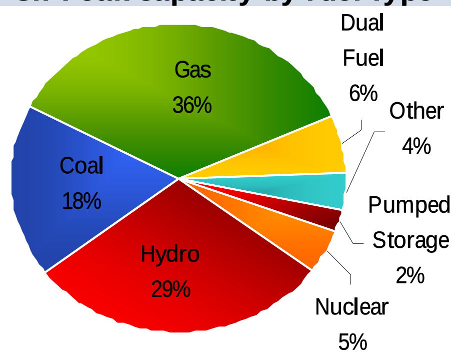
[80] http://www.spp.org/publications/2007%20SPP%20Transmission%20Expansion%20Plan%2020080131_BOD_Public.pdf

WECC

Regional Assessment Summary

2009 Summer Projected Peak Demand	MW
Total Internal Demand	161,007
Direct Control Load Management	1,433
Contractually Interruptible (Curtailable)	2,137
Critical Peak-Pricing with Control	5
Load as a Capacity Resource	715
Net Internal Demand	156,717

On-Peak Capacity by Fuel Type



2008 Summer Comparison	MW	% Change
2008 Summer Projected Peak Demand	157,945	-0.8%
2008 Summer Actual Peak Demand	154,327	1.5%
All-Time Summer Peak Demand	161,131	-2.7%

2009 Summer Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	197,257	25.9%
Deliverable Capacity Resources	199,310	27.2%
Prospective Capacity Resources	199,310	27.2%
NERC Reference Margin Level	-	14.0%

Introduction

Western Electricity Coordinating Council (WECC) is one of eight electric reliability councils in North America. WECC is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC ensures open and nondiscriminatory transmission access among its members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.[81]

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

WECC is divided into four subregions: The Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA), the Arizona-New Mexico-Southern Nevada Area (AZ-NM-SNV) and the California-Mexico Power Area (CAMX). The NWPP is a winter peaking subregion with a large amount of hydro resources. The RMPA's peak can occur in either the

[81] http://www.wecc.biz/documents/library/publications/Revised_Bylaws_Clean_10-07-03.pdf

summer or the winter, and it has a large amount of coal generation. The AZ-NM-SNV and the CAMX subregions peak in the summer and the majority of their resources are gas fired.

WECC expects to have adequate generation capacity, reserves and transmission for the forecasted 2009 summer peak demand and energy loads. This is attributed to the combination of a lower demand forecast, additional generation resources, and transmission system enhancements. The capabilities presented in this assessment reflect plant contingent capacity transfers between subregions, but do not reflect other expected firm and non-firm transactions within the WECC Region.

Demand

The aggregate, WECC 2009 summer total internal demand is forecast to be 161,007 MW (U.S. systems 140,966 MW, Canadian systems 18,071 MW, and Mexican system 2,115 MW). The forecast is based on normal weather conditions, and is 4.3 percent above last summer's actual peak demand of 154,327 MW. The 2008 summer peak demand occurred under normal to somewhat below-normal temperatures in the Region under adverse economic conditions which has not been adjusted for weather normalization. The 2009 summer, total internal demand forecast is 0.6 percent less than last summer's forecast peak demand of 162,052 MW for the 2008 summer period. The decline in the forecast peaks can be attributed primarily to the change in economic conditions.

Table WECC - 1: WECC REGION & SUBREGION GROWTH RATES

SUMMER PEAK	WECC	NWPP	RMPA	AZ-NM-SNV	CA/MX
2008 Forecast	162,052	55,922	12,285	31,551	62,691
2008 Actual	154,327	56,172	11,579	28,892	57,725
Difference (MW)	-7,725	250	-706	-2,659	-4,966
Difference %	**-4.77%**	**0.45%**	**-5.75%**	**-8.43%**	**-7.92%**
2008 Actual	154,327	56,172	11,579	28,892	57,725
2009 Forecast	161,007	57,811	11,504	30,505	63,352
Difference (MW)	6,680	1,639	-75	1,613	5,627
Difference %	**4.33%**	**2.92%**	**-0.65%**	**5.58%**	**9.75%**
2008 Forecast	162,052	55,922	12,285	31,551	62,691
2009 Forecast	161,007	57,811	11,504	30,505	63,352
Difference (MW)	-629	1,889	-781	-630	661
Difference %	**-0.64%**	**3.38%**	**-6.36%**	**-3.32%**	**1.05%**

Note: All actual and forecast loads are monthly non-coincident

The peak demand forecasts are monthly non-coincident sums of Balancing Authority (BA) forecasts. Comparisons with hourly demand data indicate that the WECC non-coincident peak demands generally exceed coincident peak demands by two-to-four percent. WECC staff does not perform independent load forecasts. Load forecasts are provided by BAs, which reflect 1-in-2 conditions. Several of the entities use various weather scenarios (i.e., 1-in-5, 1-in-10 conditions) for other internal planning purposes. Econometric models used by various entities within the Western Interconnection consider rate effects, average area population income, etc.

Energy efficiency programs vary by location, which are generally offered by the Load Serving Entity (LSE). Programs include: ENERGY STAR builder incentive programs, business lighting rebate programs, retail compact fluorescent light bulb (CFL) programs, home efficiency assistance programs, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc. For purposes of verification, some LSEs retain independent third parties to evaluate their programs.

Demand-side management (DSM) programs offered by BAs or LSEs vary widely. In the past, WECC has reported the dispatchable load management programs using the two traditional categories of direct controlled load management (DCLM) and interruptible load. In 2008, there were 3,053 MW of DCLM and 1,054 MW of interruptible demand capability. To better quantify the effect of these programs on the reliability of the interconnection, four different categories were used by WECC to report the DSM direct-controlled dispatch participation in 2009. The 2009 internal demand forecast includes 1,433 MW of DCLM, 2,137 MW of interruptible demand capability, 715 MW of load as a capacity resource and 5 MW of Critical-Peak-Pricing. The total of 2009 DCLM products is 4,290 MW, an increase of 175 MW over last year. Of the DCLM total, approximately 65 percent is located in California. In addition, a significant operational change to DSM programs has occurred in California. In the past, these DSM programs could not be implemented until an emergency was declared. They now can be called upon during times of high demand or system stress, which should provide added flexibility and mitigate the need to declare an emergency.

Each LSE is responsible for verifying the accuracy of their DSM and energy efficiency programs. Methods for verification include: Direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage.

Generation

NERC has introduced new categories for reporting existing and future generation resources. Existing resources are reported as Existing Certain (EC), Existing Other (EO) and Existing Inoperable (EI). Future resources are known as Future Planned (FP), Future Other (FO), and Conceptual.

WECC expects 197,257 MW of EC generation to be available this summer. Additional generation from the FP and Conceptual categories could add another 2,915 MW by the end of September. The breakdown of the resources can be found on the following page in Table WECC-2 (Existing and Expected Resources). The EC hydro resource capability used for this assessment is approximately 62,934 MW, with an associated EO derate amount of 5,596 MW. The EO amount reflects river flow limitations and other factors. WECC's biomass capacity is 1,660 MW of EC, 211 MW of FP and 32 MW of conceptual.

As of January 1, 2009, the installed wind capacity in WECC is 8,788 MW. Of the reported wind capacity, 1,753 MW is considered EC and 6,540 MW is considered EO. The balance is made up of transfers between entities that are reported as net values. In 2008, the Region installed 1,775 MW of wind capacity, 291 MW is being counted as EC. An additional 1,192 MW of wind generation is scheduled to be installed by the end of September 2009. Of this, 170 MW is being counted as FP.

The method for calculating on-peak wind capacity varies and is determined by the BAs. Examples of methods used include: zero contribution from wind capacity towards meeting the on-peak demand, Use 5 percent of the installed capacity as on-peak capacity, and use of historical area-specific wind-flow patterns to determine an expected on-peak capacity.

Table WECC - 2: Existing and Potential Resources (WECC through September 30, 2009)				
	Existing Certain	Existing Other	Future Certain & Other	Conceptual
Total On-Peak Resources	**197,257**		**2,643**	**272**
Conventional Expected On-Peak	130,501		2,134	239
Wind Expected On-Peak	1,753		170	
Solar Expected On-Peak	409		20	1
Hydro Expected On-Peak	62,934		108	
Biomass Expected On-Peak	1,660		211	32
Derates or Maintenance		**15,688**	**1,045**	
Wind Derate On-Peak		6,540	1,022	
Solar Derate On-Peak		118	2	
Hydro Derate On-Peak		5,596		
Biomass Derate On-Peak			21	
Scheduled Outage - Maintenance		3,434		
Transmission-Limited Resources				
Existing, Inoperable	**0**	**0**	**0**	**0**

The 36 BAs in WECC use a variety of methods to determine their future resource requirements. Some entities file an Integrated Resource Plan (IRP) with their state regulators to establish the need for resources in order to maintain planning reserve margins or to meet state or local requirements (renewable generation standards, etc.). Other entities use optimization programs to help select the best portfolio of future resources, to minimize the amount of energy not served (ENS) and/or determine the loss of load probability (LOLP). Still others rely on the market price signals to develop the resources. The State of California has a Resource Adequacy (RA) policy that is described in more detail, in that subregion's section.

Capacity Transactions on Peak

There is a small amount (262 MW) of net firm imports into the WECC Region from outside of the western interconnection at time of peak. These are not being counted in our reserve margin calculations. Transfers within the WECC Region that are included in the reserve margin calculations reflect only plant contingent capacity transfers between subregions.

Transmission

A complete list of the transmission projects is located in the tables at the back of WECC's section, but here are some of the highlights: Since October 2008, approximately 230 miles of new, bulk power transmission lines have been put into service. There are also approximately 135 miles of additional transmission lines under-construction that are expected to be operational by the end of September 2009. Other highlights include the Palo Verde-Pinal West switchyard and its associated 500-345 kV transformer near Phoenix, and the Silvergate substation in the San Diego area. There are other bulk system transformers and capacitors are in the construction phase, which should be available prior to the end of September 2009. These include two 345-500 kV step-up transformers at the Rancho Vista Substation in the Los Angeles Area accommodating future generation, which are expected to be available June 2009. However, if there are delays, it should not impact the reliability of the bulk power system.

Operational Issues

The WECC Region is spread over a wide geographic area with significant distances between load and generation areas. The northern portion of WECC's Region is winter peaking, while its southern portion is summer peaking. Consequently, entities within the Western Interconnection seasonally exchange electric energy. However, transmission constraints between the subregions are a limiting factor in the efficient use of this energy. Due to inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level. WECC does not expect major generating unit outages, transmission facility outages, or unusual operating conditions that would adversely impact reliable operations this summer. No environmental or regulatory restrictions have been reported that are expected to adversely impact reliability. Although the overall hydro conditions within WECC are below normal, it should not adversely impact reliable operations this summer. The total energy output from the hydro resources may be reduced, but the on-peak capacity for most of the WECC Region will be unaffected.

Reliability Assessment Analysis

WECC does not have a mandatory reserve requirement for the interconnection. The establishment of individual reserve margins is left to the BAs or state regulators with whom the BAs interface. WECC does analyze the reserve margins for the various subregions as presented in Table WECC-3. WECC only considers resources within its boundaries when performing this analysis. The target reserve margins presented in Table WECC-3 were calculated using WECC's building block method as used for the 2008 Power Supply Assessment (PSA).[82] The building block approach has four elements: Contingency reserves, regulating reserves, reserves for additional forced outages, and reserves for 1–in–10 weather events. Separate building block values were developed for each Balancing Authority and then aggregated by subregions for the analysis. The WECC staff does not perform LOLP studies.

For the peak summer month of July 2009, WECC expects a reserve margin of 27.2 percent. WECC's expected reserve margin for the same period last year was 19.8 percent. This increase in the expected reserve margin is mainly due to new generation and lower load forecasts.

As described earlier, many demand response programs are used in the Western Interconnection. Each BA may treat them differently when applying them to their resource adequacy assessment. Most of the BAs consider these programs to be load modifiers, which allow the demand to be reduced or curtailed when needed to maintain reliability. When performing the PSA, the load associated with demand response programs is considered part of the total load, and it is treated the same as firm load for the study. However, the quantity of reserves are calculated from the firm load and then added to the total load. In addition, some of the BAs use demand response programs as part of their ancillary reserves.

[82] http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=56

Table WECC - 3: WECC Regional and Subregional Reserve Margins				
	Target	Forecasted		
	Minimum Building Block Reserve Margin	Margins based on resources as of 01/01/2009	Margins based on non-conceptual resource additions subsequent to 01/01/2009	Margins based on all resource additions subsequent to 01/01/2009
NWPP - U.S.*	13.50%	47.70%	44.50%	44.50%
Rocky Mountain Power Area	11.80%	14.20%	16.90%	16.90%
Arizona–New Mexico–So. Nevada	13.30%	21.20%	21.80%	21.80%
California – Mexico Subregion* (US)	15.30%	11.10%	15.30%	15.30%
WECC U.S.**	14.00%	24.80%	26.00%	26.00%
NWPP - Canada*	11.30%	28.50%	30.00%	30.50%
California – Mexico Subregion* (MX)	14.30%	8.10%	15.20%	15.20%
WECC Total**	**13.70%**	**25.90%**	**27.20%**	**27.20%**

*** The reserve margins stated in the table do not represent sustained capacity. See detailed explanation in NWPP section. Non-conceptual resources include a 1350MW capacity exchange between NWPP and California (CAUS at 1200MW and CAMX at 150MW) during California's peak in August.**

**** The WECC Total is simply the weighted average of the subregional totals and does not represent capacity that is available to any subregion.**

Ten states with load residing within WECC have issued state-mandated Renewable Portfolio Standards.[83] This has accelerated the use of renewable resources, a majority of which is wind generation. In some areas, where large concentrations of wind resources have been added, BAs have increased the amount of regulating reserve available to accommodate the increased variability. If this trend continues, BAs with increasing levels of wind generation likely will need to carry additional operating reserves. Additional tools also have been implemented to manage wind variability and uncertainty. To help minimize the uncertainty in wind generation output, wind forecasting systems have been implemented by some BAs. In addition, to reduce the amount of additional operating reserves needed, some BAs have developed wind curtailment and wind limitation procedures when generation exceeds available regulating resources.

There are a variety of methods used to account for the capacity of wind resources. Some BAs do not count wind resources towards their capacity to meet loads. Others use historical information to project how much capacity they can count towards meeting their demand. Alternately, one BA establishes the capacity value for wind using a Load Duration Curve (LDC) method, which averages the wind contribution during the highest 90 summer load hours.

There have been some deferrals or cancellations of the constructing of new generation and transmission projects due to changes in projected demand. This has been caused, in part, by a recent downturn in economic conditions. These deferrals have not impacted reliability.

[83] http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

WECC does not have a definition for generation deliverability, but transmission facilities are planned in accordance with NERC and WECC planning standards. These standards establish performance levels, which are intended to limit the adverse effects of each transmission system's capability to serve its customers, to accommodate planned inter-area power transfers, and to meet its transmission obligation to others. The standards do not require construction of transmission to address intra-regional transfer capability constraints. WECC's Operating Transfer Capability Policy Committee (OTCPC) has a System Operating Limits (SOL) study and review process. This process divides WECC into regional study groups that are responsible for performing and approving seasonal studies on significant paths in their region to determine the maximum SOL rating.

Operating studies are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures.

The WECC TPL-(001 thru 004)-WECC-1-CR-System Performance Criteria provides guidance on voltage support requirements, reactive power requirements, and disturbance performance criteria. [84] The WECC transient voltage dip criteria is contained in these criteria. Planning authorities and transmission planners are responsible for ensuring that their areas are compliant with the WECC criteria and TPL Standards 001 through 004.

The WECC Studies Review Work Group (SRWG) has an annual study program, which compiles and develops WECC-wide power flow and stability models (base cases). The WECC staff and the SRWG perform selective transient dynamic and post-transient analysis on these base cases and the results of these studies are compiled in the study program report.[85]

Each year, the WECC staff sends a data request to the Technical Studies Subcommittee (TSS) and the SRWG asking for areas of "potential voltage stability problems and the measures that are being taken to address the problems throughout the WECC Region." The results of this survey are compiled and posted on the WECC website as the Voltage Stability Summary.[86]

WECC does not perform fuel supply interruption analysis. Historically, coal-fired plants have been built at-or-near their fuel source, and they generally have long-term fuel contracts with mine operators. Gas-fired plants mostly are located near major load centers and rely on relatively abundant western gas supplies. Some of the older gas-fired generators in the Region have backup fuel capability and they normally carry an inventory of backup fuel. However, WECC does not require verification of the operability of the backup fuel systems, and it does not track onsite backup fuel inventories. The majority of the newer generation is gas-fired only, which may increase the Region's exposure to interruptions of that fuel source. During the summer period, adverse weather conditions should not impact fuel supplies.

The aggregate water conditions within WECC are expected to be below normal. However, hydro conditions throughout the West vary greatly by river system and year. In some areas, the amount of energy may be reduced, but the capacity still will be available. The NWPP

[84] http://www.wecc.biz/documents/library/Standards/Criteria/TPLstd001-004%204-28-08%20clean.pdf
[85] http://www.wecc.biz/TechStudies/index.html
[86] http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=30

Subregional discussion provides more detail on this subject. It is not expected that the hydro conditions will impact the reliability for the 2009 summer period.

Subregions

Northwest Power Pool (NWPP) Area

The Northwest Power Pool (Power Pool) area is comprised of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, and Utah; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. The Power Pool, in collaboration with its members, has conducted an assessment of reliability in response to questions regarding the ability of the Power Pool to meet its load requirements during the 2009 summer. Analyses indicate the Northwest area will be able to meet firm loads and required operating reserve margins (regulating reserve and contingency reserve) for 2009 summer operations, assuming normal ambient temperature and normal weather conditions.

The Power Pool is typically a winter peaking subregion and expects to have adequate resources this summer. The forecasted summer season, peak month for the NWPP U.S. and Canada is July for 2009.

This assessment is valid for the entire Northwest Power Pool area; however, these overall results do not necessarily apply to all sub-areas (individual members, BAs, states and provinces) when assessed separately.

In 2007, Sacramento Municipal Utility District (SMUD) BA and Turlock Irrigation District (TID) BA joined the Power Pool to share reserves across transmission interconnections to the NWPP. However, for purposes of the 2009 summer assessment, SMUD and TID BA's assessments have not been integrated into the NWPP assessment process, since they are included in the California-Mexico subregion where they are geographically located.

Table WECC - 4: NWPP SUBREGION GROWTH RATES

SUMMER PEAK	TOTAL AREA	NWPP U.S.	CANADA
2008 Forecast	55,922	38,125	17,797
2008 Actual	56,172	38,783	17,389
Difference (MW)	250	658	-408
Difference %	**0.45%**	**1.73%**	**-2.29%**
2008 Actual	56,172	38,783	17,389
2009 Forecast	57,811	39,740	18,071
Difference (MW)	1,639	957	682
Difference %	**2.92%**	**2.47%**	**3.92%**
2008 Forecast	55,922	38,125	17,797
2009 Forecast	57,811	39,740	18,071
Difference (MW)	1,889	1,615	274
Difference %	**3.38%**	**4.24%**	**1.54%**

Note: All actual and forecast loads in this table are non-coincident

Demand and Energy

The Northwest Power Pool 2008 coincidental summer peak of 54,190 MW occurred on August 14, 2008. The 2008 coincidental summer peak was 98.17 percent of the forecast; however, the coincidental peak occurred during below-normal temperature conditions. Normalizing for temperature variance (50 percent probability), the 2008 coincidental peak would have been 55,000 or 99.64 percent of the forecast.

The 2009 summer peak forecast for the Power Pool area, as one single entity, of 54,500 MW is based on normal weather, reflects the prevailing economic down-turn, and has a 50 percent probability of not being exceeded. Extreme temperatures have the potential of increasing the coincidental peak by 3,500 MW. The Power Pool peak Area Load forecast includes approximately 200 MW of interruptible demand capability and load management. In addition, the load forecast incorporates any benefit (load reduction) associated with demand-side resources that are not controlled by the individual utilities. Some of the entities within the Power Pool area have specific programs to manage peak issues during extreme conditions. Normally these programs are used to meet the entities operating reserve requirements and they have no discernable impacts on the projected Power Pool area peak load.

Under normal weather conditions, the Power Pool area does not anticipate dependence on imports from external areas during summer peak demand periods. However, if lower-than-normal precipitation occurred, it may be extremely advantageous to maximize the transfer capabilities from outside the Northwest Power Pool area to reduce reservoir drafts and to aid reservoir filling.

Resource Assessment

Approximately 60 percent of the Power Pool resource capability is from hydro generation. The remaining generation is produced from conventional thermal plants and miscellaneous resources, such as non-utility owned, gas-fired cogeneration or wind.

Table WECC - 5: Existing and Potential Resources - (NWPP Through September 30, 2009				
	Existing Certain (MW)	Existing Other (MW)	Future Certain & Other	Conceptual (MW)
Total On-Peak Resources	**80,357**		**699**	**271**
Conventional Expected On-Peak	33,656		356	239
Wind Expected On-Peak	726		100	
Solar Expected On-Peak	0		0	
Hydro Expected On-Peak	45,149		79	
Biomass Expected On-Peak	826		164	32
Derates or Maintenance		**10,017**	**721**	
Wind Derate On-Peak		3,176	700	
Solar Derate On-Peak		0		
Hydro Derate On-Peak		3,695		
Biomass Derate On-Peak			21	
Scheduled Outage – Maintenance		3,146		
Transmission-Limited Resources				
Existing, Inoperable	**0**	**0**	**0**	**0**

Hydro Capability

Northwest power planning is done by sub-area. Idaho, Nevada, Wyoming, Utah, British Columbia and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington and Western Montana) coordinates the operation of its hydro resources to serve its demand. The Coordinated System hydro operation is based on critical water planning assumptions (currently the 1936-1937 water-year). Critical water in the

Coordinated System equates to approximately 11,000 average MW of firm energy, load-carrying capability, when reservoirs start full. Under average water year conditions, the additional non-firm energy available is approximately 3,000 average MW.

The 2009 March final forecast for the January through July Volume Runoff (Columbia River flows) at The Dalles, Oregon is 86.2 million acre- feet (Maf), or 80 percent of the 30-year average.

Last year, the Coordinated System hydro reservoirs refilled to approximately 90 percent of the Energy Content Curve by July 31, 2008.

April through July

This period is the refill season when reservoirs store spring runoff. The water fueling associated with hydro-powered resources can be difficult to manage because there are several competing purposes. These include: Current electric power generation, future (winter) electric power generation, flood control, biological opinion requirements in the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation and the refilling of the reservoirs each year. Whenever precipitation levels fall below normal, balancing these interests becomes even more difficult.

With the competition for water, 2009 power operations may be difficult. The goal is to manage all the competing requirements while refilling the reservoirs to the highest extent possible.

Sustainable Hydro Capability

Operators of the hydro facilities maximize the hydrology throughout the year, while ensuring that all competing purposes are evaluated. Although available reserve margin at the time of peak demand can be calculated to be greater than 20 percent, this can be misleading. Since hydro can be limited due to conditions (either lack of water or imposed restrictions), the expected sustainable capacity must be determined before establishing a representative reserve margin. In other words, the firm energy load carrying capability (FELCC) is the amount of energy that the system may be called on to produce on a firm or guaranteed basis during actual operations. The FELCC is highly dependent upon the availability of water for hydro-electric generation.

The Power Pool has developed the expected sustainable capacity based on the aggregated information and members estimates of their own hydro generation. Sustainable capacity is for periods at least greater than two-hours during daily peak periods assuming various conditions. This aggregated information yielded a reduction for sustained capability of approximately 7,000 MW. This reduction is more specific to the Northwest in the winter; however, under summer extreme low water conditions, it affects summer conditions.

Thermal Generation

No thermal plant or fuel problems are anticipated. To the extent that existing thermal resources are not scheduled for maintenance, thermal and other resources should be available as needed during the summer peak.

External Resources
No external resources to the Northwest Power Pool area are assumed for the summer.

Integration of Variable Generation
Several states have enacted renewable portfolio standards that will require some Power Pool members to satisfy at least 20 percent of their load with energy generated from renewable resources by the mid-2010 decade. This may result in a significant increase in variable generation within the Power Pool area, creating new operational challenges that will have to be addressed in the future. Some of the safety net programs, such as contingency reserve and under frequency load shedding, will be re-evaluated for effectiveness.

The Power Pool area estimated installed wind generation capacity for December 2008 is approximately 5,700 MW. This is anticipated to increase by June 2009 to 6,400 MW. With the increasing variable generation, conventional operation of the existing hydro and thermal resources will be impacted.

The wind generation manufactures' standard operating temperature for wind turbines range from -10° C to + 40° C (14° F to 104° F). During the summer peaking period, the temperature in the areas where the majority of the wind turbines are located can exceed 104°F, resulting in a loss of capacity from wind generation during those periods.

In addition, there is a risk of over-generation in the spring and fall. When both the wind and hydro generation are both in high-generation mode, and given the environmental constraints on dissolved gases in the river, there are times when generation may exceed load and the ability to export.

Planning Margin
The Northwest Power Pool area does not have one explicit method for determining an adequacy margin. Bonneville Power Administration uses the Northwest Power and Conservation Council's resource adequacy standard, which establishes targets for both the energy and capacity adequacy metrics derived from a loss of load probability analysis. Others will use NERC's reserve margin approach.

Since no one method exists for the entire Northwest Power Pool area, we have elected to use NERC's reserve margin analysis for the summer assessment. The 2009 Power Pool area generating capability is projected to be 84,000 MW, prior to adjusting for maintenance. In determining planning reserve margin, one must further adjust both load and capability for a severe weather event. A severe weather event for the entire Power Pool area will add approximately 3,500 MW of load while, at the same time under extreme water restrictions, the sustained hydro generation would reduce the capability by 7,000 MW. In addition, under the severe weather, wind generation is expected to be minimal. The estimated operating reserve requirement is approximately 3,800 MW. Accounting for a severe weather event and the operating reserve yields a planning reserve margin of approximately 18 percent, which is relatively the same as last year.

Transmission Assessment
Constrained paths within the Power Pool area are known, operating studies modeling these constraints have been performed, and operating procedures have been developed to ensure safe and reliable operations. For example, strong load growth in the St. George, Utah, portion of the PacifiCorp East (PACE) balancing area has the potential to affect local reliability during single contingency events, should the event correspond with high temperatures in the area. In preparation, PACE has developed emergency procedures for use during those events.

Outage Coordination
The NWPP coordinated outage (transmission) system (COS) was designed to ensure that outages could be coordinated among all stakeholders (operators, maintenance personnel, transmission users and operations planners) in an open process. This process had to ensure that proper operating studies were accomplished and that transmission impacts and limits were known. It fulfills a requirement from the 1996 West Coast disturbances that the system be operated only under studied conditions. The WECC Reliability Coordinator (RC) is involved in the outage coordination process and has direct access to the outage database.

Monthly Coordination
The process requires NWPP members to designate significant facilities that will impact system capabilities if out of service alone or in conjunction with another outage. The significant facilities are defined and updated annually by the NWPP members. The scheduled outage of these critical facilities is posted on a common database. All utilities post proposed significant outages on WECC's Coordinated Outages System (COS). Outages are to be submitted to the COS at least 45 days ahead of the month that they are proposed to occur to be viewed by interested entities. The involved entities then facilitate the NWPP coordination of all these outages. Entities can comment on the potential impacts, and schedules may be adjusted to maximize reliability and minimize market impacts. If coincidental outages cause too severe of an impact, the requesting utilities work together to adjust schedules accordingly. A final outage plan is posted with estimated path capabilities 30 days prior to the month the outages will occur. Detailed operational transfer capability studies are then performed, and the limits for each affected path are posted at least 15 days prior to the outage.

Emergency outages can be requested outside these schedule guidelines. Emergency outages are coordinated among adjacent utilities to minimize system exposure. Utilities can use the COS system to ensure that system topology is correct for next day studies. As transmission operators increase the amount of short-term outages in addition to the significant outages, the WECC RC will be able to access to the WECC COS database and use the final outage schedule in its real-time system analysis. This coordinated outage process has been very effective. The outage information is used by NWPP member utilities to perform system studies to maximize system reliability.

Semi-annual planning - Long-Range Significant Outage Planning (LRSOP)
The NWPP staff facilitates outage meetings every six months with each utility's outage coordinator to discuss proposed longer-term outages. Utilities discuss anticipated outages needed for time-critical construction and periods where transmission capacity may need to be

maximized. The outages are posted on the WECC COS and on the individual companies' OASIS sites.

Specific responsibilities of LRSOP include:

- Share outage information with all parties affected by outages of significant equipment (i.e. equipment that affects the transfer capability of rated paths). Information is shared two times each year for a minimum of a six- month period. The first meeting each year coordinates outages for July through December. The second meeting coordinates outages for January through June.
- Review the outage schedules to ensure that needed outages can be reliably accomplished with minimal impact on critical transmission use.
- Outage coordinators are to post the outages on the Coordinated Outages System within the applicable timeframes.

Northwest Operation and Planning Study Group

A recommendation following the 1996 West Coast disturbances was the requirement to not operate in conditions that have not been studied. Therefore, a study and review process calculating seasonal operating transfer capability (OTC), also known as system operating limits (SOL), for critical paths in WECC. The NWPP entities had, through a cooperative working relationship, shared information prior to the formalization of the process. The initial focus for this effort was the California-Oregon Intertie (COI) because this path was involved in both 1996 disturbances. The seasonal study process eventually was expanded from the COI to all WECC paths listed in the WECC path-rating catalog.

The WECC created the Operating Transfer Capability Policy Committee (OTCPC), and a corresponding SOL study and review process. This process divided the WECC into regional study groups. Each is responsible for performing and approving seasonal studies on significant paths in their region to determine the maximum SOL ratings. The NWPP formalized the Northwest Operation and Planning Study Group (NOPSG), which is composed of the path operators and/or owners of critical Northwest transmission paths, and any other interested NWPP members. NOPSG approved seasonal studies and SOLs are presented to the OTCPC for final approval. The SOLs approved by the OTCPC are then posted as the maximum path capacity for the given season.

The NOPSG charter and WECC OTCPC handbook are available on the NWPP Web site in its Operating Committee area.

Next Day Operating Studies

Additional path curtailments may be required depending upon current system conditions and outages. These curtailment studies are performed by the individual path operators based on the outage schedule developed through the COS process. According to the COS process, these studies are performed at least 15 days prior to the outage. Individual path operators and transmission owners also may perform updated, next-day studies to capture emergency outage requests and current system conditions – such as generation dispatch to determine if the SOL studies and limits are still accurate. Based on these studies, additional SOL curtailments may be made by the path operators. The modified SOL's are posted on the individual transmission owners OASIS and the RC is notified.

The WECC RC also performs system studies to ensure interconnected system reliability. The WECC RC performs real-time system thermal studies to evaluate current operating conditions across the entire Interconnection. The WECC RC is in the process of incorporating real-time voltage tools to complement the thermal analysis currently being performed. Transient stability analysis capability is planned in the future. When the WECC RC observes real-time reliability problems, it contacts the path operator to discuss the issue and work on a solution. The WECC RC will make a directive for action if there is an imminent reliability threat and the Balancing Authority does not eliminate the reliability issue within an appropriate time frame.

Voltage Stability

The WECC-1-CR System Performance Criteria (requirement WRS3) is used to plan adequate voltage stability margin in the Northwest Power Pool area as appropriate. Simulations are used to ensure that system performance is adequate and meets the required criteria.

Contingency Reserve Sharing Procedure

As permitted by NERC and WECC criteria and standards, NWPP's Operating Committee has instituted a Reserve Sharing Program for contingency reserve. Those who participate in a reserve sharing group are better positioned to meet the NERC disturbance control standard because they have access to a deeper and more diverse pool of shared reserve resources. Also, an increase in efficiency is obtained since the shared reserve obligation for the entire group is less than the sum of each participant's reserve obligation computed separately.

By sharing contingency reserve, the participants are entitled to use not only their own "internal" reserve resources, but to call on other participants for assistance if internal reserve does not fully cover a contingency. The reserve sharing process for the NWPP has been automated. A manual backup process is in place if communication links are down or if the computer system for reserve sharing is not functioning correctly.

The NWPP is designated as a reserve sharing group (RSG) as provided under WECC Operating Reliability Criteria. Each member of the RSG submits its contingency reserve obligation (CRO) and its most severe single contingency (MSSC) to a central computer. The combined member CRO must be larger than the RSG's MSSC. If not, then each member's CRO is proportionally increased until this requirement is met. When any RSG member loses generation, it has the right to call upon reserves from the other RSG members as long as it first has committed its own CRO. A request for contingency reserve must be sent within four minutes after the generation loss, and the received contingency reserve only can be held for 60 minutes. A request is sent via the member's energy management system to the central computer. The central computer then distributes the request proportionally among members within the RSG. Each member may be called to provide reserve up to its CRO. Critical transmission paths are monitored in this process to ensure that SOL limits are not exceeded. If a transmission path SOL is exceeded, the automated program redistributes the request among RSG members that are delivering reserve along non-congested paths. The WECC RC continuously monitors the adequacy of the RSG reserve obligation, MSSC, and the deployment of reserve. If a reserve request fails due to various reasons, backup procedures are in place to fully address the requirements.

Reliability Coordinator
The Reliability Coordinator (RC) is responsible for monitoring, advising and transmission service between and within the interconnected systems of all Balancing Authorities (BAs) within the Western Interconnection.

Strategic Undertakings

- Adequacy Response Team
  The Northwest has developed an Adequacy Response Process whereby a team avoids power emergencies by promoting regional coordination and communications. Essential pieces of that effort include timely analyses of the power situation, and communication of that information to all parties, including utility officials, elected officials and the general public.
- Emergency Response Team (ERT)
  In Fall 2000, the Power Pool developed an Emergency Response Process to address immediate power emergencies. The ERT remains in place and would be used in the event of an emergency. The ERT would work with all parties in pursuing options to resolve the emergency, including load curtailment and or imports of additional power from other areas outside of the Power Pool.

Conclusions
In view of the present overall power conditions, including the forecasted water condition, the Power Pool area estimates that it will be able to meet firm loads including the required operating reserve. Should any resources be lost to the area beyond the contingency reserve requirement (or loads greater than expected because of extreme weather), the Power Pool area may have to look to alternatives that may include emergency measures to meet obligations.

California–Mexico Power Area

The 2009 summer peak demand forecast of 63,352 MW is 9.8 percent greater than last summer's actual peak demand of 57,725 MW, which is 1.0 percent higher than last summer's forecast peak demand of 62,691 MW. Last year's actual demand was 7.9 percent less than the forecast. While the subregion's 2008 summer peak demand occurred during a period of normal to slightly cooler-than-normal temperatures, the reduced demand was more a reflection of the slowing economy. The California Independent System Operator (CAISO) is awaiting a revised forecast and it is expected to be less due to current economic conditions. The forecast peak demand includes 2,816 MW of DCLM. The subregion's combined (California and Mexico) projected reserve margin for its summer peak month (August) is 15.3 percent, which is above the target reserve margin of 15.2 percent. The 15.3 percent reserve margin includes 4,673 MW of plant specific transfers from the NWPP, RMPA and the AZ-NM-SNV subregions. An additional 1,427 MW of expected purchases from the other subregions is also planned. The entities are expected to enter into more firm non-plant contingent purchases and the subregion is expected to have adequate resources.

California has a RPS to achieve 20 percent renewable energy by 2010 and 35 percent by 2020. The CAISO determines the Net Qualifying Capacity of renewable resources by using a 3-year monthly average for determining the capacity contribution of variable resources. The CAISO also publishes a monthly wind contribution factors [87] and has developed solutions to integrate[88] of large amounts of renewable resources within their BA area.

Table WECC - 6: CA-MEXICO (CA/MX) SUBREGION GROWTH RATES			
SUMMER PEAK	CA/MX U.S.	CA/MX U.S.	CA/MX Mexico
2008 Forecast	62,691	60,474	2,223
2008 Actual	57,725	55,688	2,037
Difference (MW)	-4,966	-4,786	-186
Difference %	**-7.92%**	**-7.91%**	**-8.37%**
2008 Actual	57,725	55,688	2,037
2009 Forecast	63,352	61,237	2,115
Difference (MW)	5,627	5,549	78
Difference %	**9.75%**	**9.96%**	**3.83%**
2008 Forecast	62,691	60,474	2,223
2009 Forecast	63,352	61,237	2,115
Difference (MW)	661	763	-108
Difference %	**1.05%**	**1.26%**	**-4.86%**
Note: All actual and forecast loads in this table are non-coincident			

The California Public Utilities Commission (CPUC) has an established a year-ahead and monthly System Resource Adequacy Requirement[89] (RAR) for load serving entities (LSEs) under the jurisdiction of the (CPUC). The RAR requires LSEs to make a year-ahead System and Local RAR compliance filing that demonstrates compliance with the 90 percent of system RAR obligation for the five summer months of May through September, as well as 100 percent of the Local RAR for all 12 months by the end of October. DCLM products are included as resources to meet the LSE's RAR.

Prior to the end of September 2009, California is projecting to have over 1,100 MW of resources become operational (950 MW on-peak). These resources include wind farms, biomass units, solar facilities, fuel cells, and traditional generation. The forecasted peak month for California and Mexico is August for 2009.

The CAISO performed a preliminary summer assessment last winter for their BA. A hydro derate scenario was developed to make a preliminary assessment to determine the impact continued drought might have in California on 2009 operations at time of peak. A public

[87] http://www.caiso.com/202f/202f9a882ec90.xls
[88] http://www.caiso.com/1c51/1c51c7946a480.html
[89] http://www.cpuc.ca.gov/PUC/hottopics/1Energy/resourceadquacy/_060824_resourceadequacyletter.htm

statement was made at the February 3, 2009, "CEO Report to the CAISO Board of Governors."[90] In that statement, it was mentioned that it would be premature to make an official supply/demand forecast with two months of typical snow accumulation time remaining. However, the early outlook of the supply/demand picture would be about the same as in 2008. If the drought continues, it was expected to lower the hydro supplies within the CAISO by about 3,000 MW. The impact of this could be offset partially by the 1,500 MW of new generation that is being (or has been) constructed, and that should be in service before summer. It also pointed out that loads were down due to the slowing economy and that also would help offset any hydro decrease. Since the time that statement was made, hydro concerns have lessened to some degree, but no new analysis has been performed. California is in the third year of a drought and snowpack is currently 84 percent of normal[91]. The snowpack varies greatly throughout California, and there are some areas with no problems. Most of the hydro generators in the state are not reliant on reservoirs, but there is the possibility that some hydro deratings may take place if the drought continues in the other areas. Import capabilities are adequate to replace capacity and energy shortfalls in the California hydro system.

Table WECC - 7: Existing and Potential Resources - (CAMX through September 30, 2009)

	Existing Certain (MW)	Existing Other (MW)	Future Certain & Other	Conceptual (MW)
Total On-Peak Resources	**62,926**		**1,450**	
Conventional Expected On-Peak	48,661		1,314	
Wind Expected On-Peak	726		40	
Solar Expected On-Peak	351		20	
Hydro Expected On-Peak	12,452		29	
Biomass Expected On-Peak	736		47	
Derates or Maintenance		**3,639**	**239**	
Wind Derate On-Peak		2,246	237	
Solar Derate On-Peak		118	2	
Hydro Derate On-Peak		1,158		
Biomass Derate On-Peak				
Scheduled Outage – Maintenance		117		
Transmission-Limited Resources				
Existing, Inoperable	**0**	**0**	**0**	**0**

The CAISO performed an exhaustive generation deliverability study in 2006 of all existing generation. All new generation added since that time has been demonstrated as deliverable, along with existing generation and imports. Although several major constrained transmission paths have been upgraded in recent years, path constraints still exist. Operating procedures are in place to manage any high-loading conditions that may occur during the summer. Entities within the area report having no concerns with maintaining adequate reactive reserve margins.

All power plants in California are required to operate in accordance with strict air quality environmental regulations. Some plant owners have upgraded emission control equipment to remain in compliance with increasing emission limitations, while other owners have chosen to

[90] http://www.caiso.com/234b/234b9650459d0.pdf
[91] http://cdec.water.ca.gov/water_cond.html

discontinue operating some plants. The effects of owners' responses to environmental regulations have been accounted for in the area's resource data, and it is not expected that environmental issues will have additional adverse impacts on resource adequacy within the area.

Los Angeles Department of Water and Power's 2008 Ten Year Transmission Assessment identified two system constraints that could impact reliability in the 2009 summer and onward. They are:

1. An N-2 contingency (multiple outages) of Rinaldi-Tarzana 230 kV lines 1 & 2 would overload Northridge-Tarzana 230 kV Line 3. The recommended mitigation plan is to develop a load-shedding program in Tarzana area to relieve loading on the North ridge-Tarzana Line 3 during this double contingency in the short term (1-3 years); then increase capacity of this line for the long term. This plan satisfies NERC TPL-003-0.
2. An extreme event contingency of RS-E (complete outage of Toluca Substation), results in multiple post-contingency overloads. The suggested mitigation plan is to develop a load-shedding program at RS-H (Hollywood area) when voltage dips below ~ 0.85pu. This would mitigate overloads and undervoltage conditions created by this Category D event. This improvement is not required for this Category D event according to NERC TPL-004-0.

The reactive power limited areas in the CAISO are: Greater Bay Area (PG&E – San Francisco Bay Area), LA basin (SCE) and the San Diego area (SDG&E). In each of those areas the CAISO has developed reactive power reserve monitoring tools and nomograms to monitor and ensure adequate reactive power available to protect those areas.

The Southern California area imports significant amounts of power. It is expected that the transmission into that area of the Western Interconnection will be used much of the time. As in the past, any unplanned major transmission, generation outages or extreme temperatures may cause resource constraints in the Southern California area. The transmission system is considered adequate for all projected firm transactions and significant amounts of economy energy transfers. Reactive reserve margins are expected to be adequate for all expected peak-load conditions in all areas. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems.

The other BA's in the subregion expect to have adequate resources.

Rocky Mountain Power Area

The Rocky Mountain Power Area's 2009 summer peak demand forecast of 11,504 MW is 0.6 percent less than last summer's actual peak demand of 11,579 MW. It also is 6.3 percent less than last summer's forecast peak demand of 12,285 MW. Last summer's peak demand was lower than expected due to the declining economic conditions. The forecast peak demand includes 285 MW of interruptible demand capability. The projected reserve margin for the area's peak month (July) is 16.9 percent, which well above the target reserve margin of 11.8 percent. (Public Service of Colorado (PSCo) has a reserve margin of 16 percent.)

The Colorado Renewable Portfolio Standard for municipal utilities is an energy only mandate of: 1 percent of retail sales by 2008; 3 percent by 2011; 6 percent by 2015 and 10 percent by 2020.

PSCo has conducted Effective Load Carrying Capability (ELCC) studies for wind and solar variable resources. The wind ELCC was completed in late 2006 and concluded that a reasonable capacity value for wind was 12.5 percent of nameplate capacity. The solar ELCC was filed with the Colorado PUC in December 2008. The study concluded that the reasonable capacity value for solar varies between 60 percent and 80 percent depending on location and type of solar resource. PSCo uses a 70 percent capacity value for their solar resources.

The forecasted peak month for the RMPA subregion is July for 2009. Prior to June 2009, the Fort St. Vrain combined cycle unit is scheduled to become operational and will add 300 MW to RMPA's resources for the summer. A breakdown showing the sum of conventional resources and the various renewable resource sums are shown on Table WECC-8.

Table WECC - 8: Existing and Potential Resources (RMPA through September 30, 2009)

	Existing Certain (MW)	Existing Other (MW)	Future Certain & Other	Conceptual (MW)
Total On-Peak Resources	**13,268**		**300**	
Conventional Expected On-Peak	11,830		300	
Wind Expected On-Peak	134			
Solar Expected On-Peak	4			
Hydro Expected On-Peak	1,301			
Biomass Expected On-Peak	3			
Derates or Maintenance		**1,095**		
Wind Derate On-Peak		975		
Solar Derate On-Peak		4		
Hydro Derate On-Peak		116		
Biomass Derate On-Peak				
Scheduled Outage - Maintenance				
Transmission-Limited Resources				
Existing, Inoperable	**0**	**0**	**0**	**0**

Hydro conditions for the 2009 summer period are expected to be about normal, except for downstream of the Seminoe Dam, on the lower North Platte River, and the Bighorn Basin drainage area. These are considered abnormally dry, but not in a drought status. There are no capacity implications in these areas because the Loveland Area Projects dependable capacity was calculated conservatively in anticipation of an extended period of adverse hydrology. The snowpack varies throughout the RMPA subregion, in the river basins associated with the Loveland Area Projects, where it is reported that the snowpack is 111 percent of average.

The transmission system is expected to be adequate for all firm transfers and most economy energy transfers. Although slightly different flow patterns from past years are expected on major bulk system transmission, no significant changes in flow patterns are expected. The transmission path between Southeastern Wyoming and Colorado often becomes heavily loaded, as do the transmission interconnections to Utah and New Mexico. Consequently, the WECC Unscheduled Flow Mitigation Procedure may be invoked on occasion to provide line loading relief for these paths. The Rocky Mountain Reserve Group (RMRG) provides reserve sharing to its members.

Arizona-New Mexico-Southern Nevada Power Area

The Arizona-New Mexico-Southern Nevada Power Area 2009 summer peak demand forecast is 30,505 MW, which is 5.6 percent above last summer's actual peak demand of 28,892 MW, and 3.2 percent less than last summer's forecast peak demand of 31,551 MW. Last summer's peak demand was 8.4 percent less than the forecast peak demand due to declining economic conditions. The forecast for the area includes 609 MW of load management and interruptible demand capability. The projected reserve margin for the area's peak month (July) is 21.8 percent, which is well above the target reserve margin of 13.3 percent.

Western Area Lower Colorado (WALC) controls several of the large hydro dams in the subregion. WALC reports that the Lower Colorado River Basin is in the 9th year of an unprecedented drought. However, study projections[92] developed monthly by the U.S. Bureau of Reclamation Lower Colorado Region (USBRLC) currently indicate that there is ample storage to meet all federal load obligations and peaking requirements for the 2009 summer. Should the drought conditions deteriorate significantly beyond projections, the USBRLC has adopted detailed interim guidelines for the coordinated operation of Hoover Dam and Glen Canyon Dam under shortage and low reservoir conditions. Many of the BAs are members of the Southwest Reserve Sharing group.

The forecasted peak month for the AZ-NM-SNV subregion is July for 2009. Prior to July, three combustion turbines (Newman 1&2 and LANL TA-3) and one wind farm (High Lonesome Mesa Wind Farm) is scheduled to be operational.

Table WECC 9: Existing and Potential Resources - (AZ-NM-SNV through September 30, 2009)

	Existing Certain (MW)	Existing Other (MW)	Future Certain & Other	Conceptual (MW)
Total On-Peak Resources	**40,734**		**194**	**1**
Conventional Expected On-Peak	36,317		164	
Wind Expected On-Peak	33		30	
Solar Expected On-Peak	50			1
Hydro Expected On-Peak	4,031			
Biomass Expected On-Peak	95			
Derates or Maintenance		**901**	**85**	
Wind Derate On-Peak		273	85	
Solar Derate On-Peak				
Hydro Derate On-Peak		628		
Biomass Derate On-Peak				
Scheduled Outage - Maintenance				
Transmission-Limited Resources				
Existing, Inoperable	**0**	**0**	**0**	**0**

[92] http://www.usbr.gov/lc/

In Arizona, the renewable portfolio is a set of financial incentives from a large number of programs.[93] The RPS standard that Salt River Project (SRP) is responsive to is the Sustainable Portfolio Principles established by the SRP Board in 2004, and revised in 2006. These principles direct the SRP to establish a goal to meet a target of 15 percent of its expected retail energy requirements from Sustainable Resources by 2025. Sustainable Resources include all supply-side and demand-side measures that reduce the use of traditional fossil fuels.

Nevada has an RPS standard that was established by the Public Utilities Commission of Nevada (PUCN) that requires 20 percent by 2015. The PUCN also allows utilities to meet the standard through renewable energy generation (or credits) *and* energy savings from efficiency measures. At least 5 percent of the standard must be generated, acquired, or saved from solar energy systems.

The New Mexico Public Regulation Commission (PRC) established an RPS of 20 percent by 2020. In August 2007, the PRC issued an order and rules requiring that investor owned utilities meet the 20 percent by 2020 target through a "fully diversified renewable energy portfolio" which is defined as a minimum of 20 percent solar power, 20 percent wind power, and 10 percent from either biomass or geothermal energy starting in 2011. Additionally 1.5 percent must come from distributed renewables by 2011, rising to 3 percent in 2015.

SRP added the Hassayampa to Pinal West 500 kV line (near Palo Verde / Phoenix) in 2008. Tucson Electric Power Company added a 500/345 kV transformer at Pinal West to connect the station to Tucson Electric's Westwing to South 345 kV transmission line.

Based on inter- and intra-area studies, the transmission system is considered adequate for projected firm transactions and a significant amount of economy electricity transfers. When necessary, phase-shifting transformers in the Southern Utah/Colorado/ Nevada transmission system will be used to help control unscheduled flows. Reactive reserve margins have been studied, and they are expected to be adequate throughout the area.

Fuel supplies are expected to be adequate to meet summer peak demand conditions. The physical gas commodity and pipelines that supply this area have proven very reliable. In addition, firm coal supply and transportation contracts are in place, and sufficient coal inventories are expected for the summer season.

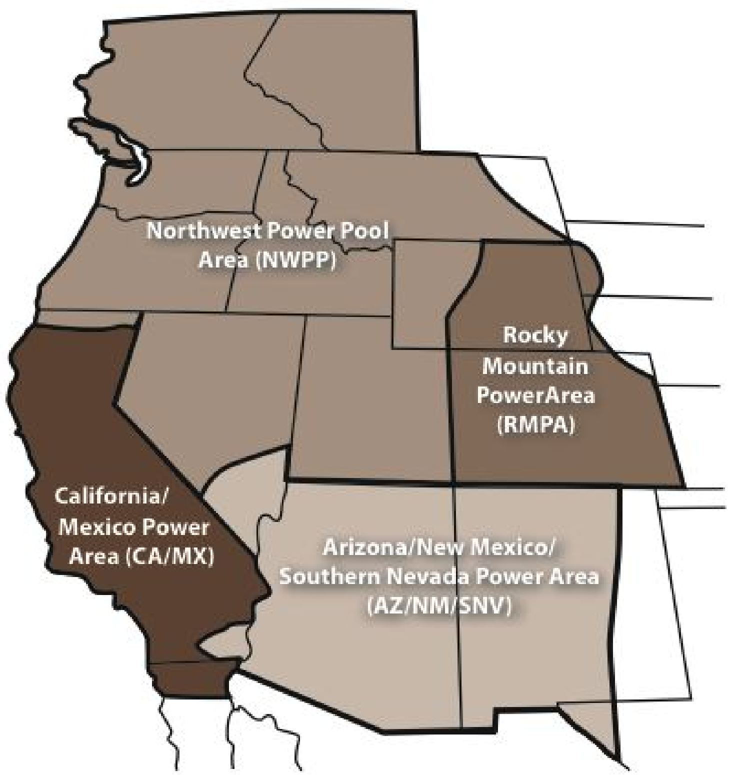
[93] http:/www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&state=AZ

Regional Description

WECC's 211 members, including 36 balancing authorities, represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 71 million people, it is the largest and most diverse of the eight NERC regional reliability organizations. Additional information regarding WECC can be found on its Web site (www.wecc.biz).

AZ/NM/SNV	230,100 sq. mi.
RMPA	167,000 sq. mi.
CAMX	156,000 sq. mi.
NWPP	1,214,000 sq. mi.
WECC TOTAL	1,760,000 sq. mi.

Figure WECC-1: WECC Subregions



WECC Scheduled Transmission Facility Additions, Retirements, and Re-ratings

Table WECC 10: WECC Transmission System Additions and Upgrades (115 kV and Above) (October 2008 through September 2009)				
Transmission Project Name	**Voltage (kV)**	**Length (Miles)**	**In-Service Date(s)**	**Description / Status**
Northwest Power Pool				
Edmonton Downtown 240 kV	240	6	11/1/2008	In-service
Rocky Reach - Andrew York	230	8	12/15/2008	In-service
Vancouver Island Trans.	230	44	12/22/2008	In-service
Danskin to Hubbard 230kV Line	230	39	2/10/2009	In service
South King County	230	10	5/1/2009	Project delayed due to outage requirements
Rocky Mountain Power Area				
Durango - Hesperus Loop	115	1	12/1/2008	In-service
Hotchkiss - Spring Creek Uprate	115	29	12/1/2008	In-service
Donkey Creek-Pumpkin Buttes	230	75	4/1/2009	Under Construction
Dry Fork - Hughes Line	230	17	5/31/2009	Under Construction
Dry Fork - Carr Draw Line	230	23	5/31/2009	Under Construction
Arizona-New Mexico-So. Nevada				
Southeast Valley Project	500	51	6/1/2008	In-service
Hassayampa - Pinal West				
Navajo Trans. Project Phase 1	500	189	4/1/2009	Project Delayed until 2014
Springerville 4 Transmission Upgrade	500	0	5/15/2009	Under construction Silver King - Goldfield 230kV line upgrade
California-Mexico Power Area				
Metcalf-Moss Landing 230 kV Reconductoring (T-867)	230	70	10/11/2008	Operational
Carver - McLoughlin	230	5	11/1/2008	In-service
Split Devers - Mirage	115	7	1/9/2009	Operational
Lugo - Rancho Vista	500	23	3/2/2009	Operational
Rancho Vista - Serrano	500	30	3/2/2009	Operational
Rancho Vista - Pauda (Circuit #1)	230	15	5/1/2009	Under construction
Rancho Vista - Mira Loma (Circuit #1)	230	7	5/1/2009	Under construction

Table WECC 11: 2009 SUMMER ASSESSMENT - TRANSFORMER INFORMATION				
Transformer Project Name	High Side Voltage (kV)	Side Voltage (kV)	In-Service Date(s)	Description/ Status
Northwest Power Pool				
Copco 230/115 kV Transformer	230	115	12/1/2008	
Andrew York 230/115 Auto	230	115	12/15/2008	Operational
Danskin Substation	230	138	5/1/2009	Available if needed.
Three Peaks 345/138kV	345	138	6/1/2009	
Oquirrh 345kV/138kV transformer	345	138	6/1/2009	
Caribou 345kV/138kV transformer	345	138	6/1/2009	
Rocky Mountain Power Area				
Lookout 230 Sub Xfmr #2	230	69	5/1/2009	150 MVA
Arizona-New Mexico-So. Nevada				
Transformer Addition	230	92	4/15/2009	Expected for 4/15/2009
Northwest 230/138 kV Transformer	230	138	6/1/2009	
Sinatra 230/138 kV Transformer	230	138	6/1/2009	
California-Mexico Power Area				
Palo Verde – Pinal West Project	500	345	10/11/2008	Operational
San Luis Rey bank 72	230	69	11/12/2008	Operational
Silvergate-New 230kV Substation	230	69	1/6/2009	Operational
Rancho Vista Substation	500	230	6/1/2009	Construction
Encina_PQ #2	230	138	6/1/2009	

2009 SUMMER ASSESSMENT - OTHER EQUIPMENT INFORMATION								
Company	Project Name	Type of equipment	Facility	Location	Capacity or Rating	Voltage (kV)	In-Service Date(s)	Description / Status
Northwest Power Pool								
IPC	Brownlee East Capacity Increase	Series Capacitor Bank	Ontario Sub.	Ontario, OR	182 MVar	230 kV AC	5/1/2008	In-Service?
IPC	Copperfield	Series Reactor (10 ohm)	Copperfield	Oxbow, OR	1200 A	230 kV AC	6/1/2008	In-Service?
IPC	Brownlee East Capacity Increase	Shunt Capacitor Bank	Brownlee Switch yard	Brownlee, ID	75 MVar	230 kV AC	6/1/2008	In-Service?
IPC	Evander Andrews Generation	Switchyard	Hubbard Substation	Boise ID		230 kV AC	2/10/2009	In Service
LADWP	Pine Tree Wind Farm	Substation	Pine Tree	Pine Tree CA			4/1/2009	
NWMT	Mill Creek Phase Shifter	Phase Shifter	Mill Creek Sub	Anaconda MT	350 MVA	230 kV AC	6/1/2008	In Service
PAC	Red Butte 138kV Capacitor Bank	Capacitor Bank	Red Butte Sub	St. George UT	30 MVar	138 kV AC	5/1/2008	
PAC	TOT 4AVoltage Support Project - Riverton	Capacitor Bank	Riverton Sub	Riverton, WY	30 MVar	230 kV AC	6/1/2008	
PAC	TOT 4AVoltage Support Project - Latham	Capacitor Bank	Latham Sub	Latham, WY	25 MVar	230 kV AC	6/1/2008	
PAC	TOT 4A Voltage Support Project - Atlantic City	Capacitor Bank	Atlantic City Sub	Atlantic City, WY	15 MVar	230 kV AC	6/1/2008	
PAC	Camp Williams SVC - Capacitor Bank Upgrades	Capacitor Bank Upgrades	Camp Williams Sub	Bluffdale UT	200 MVar	345 kV AC	6/1/2009	
PAC	Camp Williams SVC	Static Var Compensator + Step-Down Transformer + Shunt Capacitors	Camp Williams Sub	Bluffdale UT	-125/+350 MVar	345 kV AC	06/01/2009	
PAC	Three Peaks 345 kV Series Capacitor	Series Capacitor	Three Peaks Sub	Cedar City UT	TBD MVar	345 kV AC	06/01/2009	
PAC	Three Peaks 345 kV Substation	Substation	Three Peaks Sub	Cedar City UT	450 MVA	345/138 kV AC	06/01/2009	
PAC	TOT 4AVoltage Support Project - Midwest	Capacitor Bank	Midwest Sub	Midwest, WY	30 MVar	230 kV AC	06/01/2009	
Rocky Mountain Power Area								
TSGT	York Canyon 115 kV Caps	Shunt Caps	York Canyon Sub	York Canyon NM	15 MVar	115 kV AC	9 /01/2008	In Service
TSGT	Airport 115 kV Caps	Shunt Caps	Airport Substation	Larimer CO	7.5 MVar	115 kV AC	Cancelled	
BEPC	TECKLA DVAR	STATIC VAR		TECKLA	32MVAR	69	12/31/2009	Under Construction
TSGT	Gunnison 115 kV Caps	Shunt Caps	Gunnison Sub	Gunnison CO	15 MVar	115 kV AC	12/1/2012	
TSGT	Lost Canyon 115 kV	Shunt Caps	Lost Canyon Sub	Lost Canyon CO	20 MVar+	115 kV AC	Cancelled	
PSC	Chambers 230/115 kV Interconnection Project	Substation	Chambers Substation	Chambers CO		230 kV AC	05/01/2008	

2009 SUMMER ASSESSMENT - OTHER EQUIPMENT INFORMATION, CONTINUED								
Arizona - New Mexico - So. Nevada								
APS	Capacitors (Navajo – Crystal)	Capacitor bank - series	Navajo Substation	Page AZ	136 MVar	500 kV AC	05/01/2008	
APS	Reactor replacement (Reactor 4)	Reactor	Four Corners Sub	Four Corners NM	83 MVar	500 kV AC	6/1/2010	Postponed
APS	TS4 substation	Substation	TS4 Substation	West Phoenix AZ		230 kV AC	10/1/2014	Postponed
APS	Capacitors (Cholla – Saguaro)	Capacitor bank - series	Cholla Substation	Cholla Sub	309 MVar	500 kV AC	06/01/2009	
APS	Capacitors (Moenkopi – Eldorado)	Capacitor bank - series	Moenkopi Sub	Eldorado Sub	558 MVar	500 kV AC	06/01/2009	
APS	Dugas Substation (loop-in)	Substation	Dugas Substation	Cordes Jn. AZ		500 kV AC	06/01/2009	
APS	Sugar Loaf 500/69kV	Interconnection	Sugar Loaf Sub	Snowflake AZ		500 kV AC	06/01/2009	
SRP	Springerville #4	Shunt Capacitors	Ward Sub	Tempe, AZ	150 Mvar	230kV AC	5/15/2009	Post Transient Voltage Support
SRP	Springerville #4	Shunt Capacitors	Pinnacle Peak Sub	Phoenix, AZ	150 Mvar	230kV AC	5/15/2009	Post Transient Voltage Support
SRP	Springerville #4	Shunt Capacitors	Papago Buttes Sub	Scottsdale, AZ	150 Mvar	230kV AC	5/15/2009	Post Transient Voltage Support
SRP	Springerville #4	Shunt Capacitors	Rogers Sub	Mesa, AZ	150 Mvar	230kV AC	5/15/2009	Post Transient Voltage Support
SRP	Palo Verde – Pinal West Project	Switchyard	Pinal West Sub	Mobile AZ	800 MVA	500 kV AC	10/11/2008	Operational
SRP	Palo Verde – Pinal West Project	Switchyard	Pinal West Sub	Mobile AZ	800 MVA	345 kV AC	10/11/2008	Operational
SRP	Southeast Valley Project	Switchyard	(Dinosaur)	Queen Creek AZ	280 MVA	230 kV AC	05/01/2008	In Service
SRP	EOR 9300 MW Project	Series Capacitors	Perkins Sub	Phoenix AZ	653 MVar	500 kV AC	04/01/2009	
SRP	Springerville #4	Series Capacitors	Silver King Sub	Superior AZ	157.5 MVar	500 kV AC	5/15/2009	
SRP	Springerville #4	Series Capacitors	Coronado Sub	St. John AZ	157.5 MVar	500 kV AC	5/15/2009	
WALC	Valley Farms 230-kV	Substation	Vally Farms Sub	Pinal County, AZ			5/1/2009	
WALC	Sundance 230-kV	Substation	Sundance Sub	Pinal County, AZ			7/1/2009	
WALC	Empire 115-kV	Substation	Empire Sub	Pinal County, AZ			6/1/2009	
WALC	Parker Control Panels	Substation	Parker Sub	Parker, AZ			8/31/2009	
WALC	Desalter 69-kV breaker	Substation	Desalter Sub	Yuma County, AZ			9/1/2009	
California - Mexico								
SCE	Mira Loma Substation	Shunt Capacitor #1	Mira Loma Substation	Mira Loma CA	150 MVar	500 kV AC	06/01/2009	
SCE	Mira Loma Substation	Shunt Capacitor #2	Mira Loma Substation	Mira Loma CA	150 MVar	500 kV AC	06/01/2009	
SCE	Rancho Vista Substation	Substation	Rancho Vista Sub	Etiwanda CA		500 kV AC	06/01/2009	Construction
SDGE	Otay Mesa PPA Project	Switchyard	Otay Mesa Sub	San Diego CA		230 kV AC	9/29/2008	Operational
SDGE	Silvergate-Voltage Support	Capacitors	Silvergate Sub	San Diego CA		230 kV AC	1/6/2009	Operational
SDGE	Silvergate-New Substation	Substation	Silvergate Sub	San Diego CA		230 kV AC	1/6/2009	Operational

Abbreviations Used in this Report

A/C	Air Conditioning
AEP	American Electric Power
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
BA	Balancing Authorities
BCF	Billion cubic feet
BCFD	Billion cubic feet per day
CA-MX-US	California-México (Subregion of WECC)
CFE	Commission Federal de Electricidad
CFL	Compact Fluorescent Light
CMPA	California-Mexico Power Area
COI	California-Oregon Intertie
COS	Coordinated Outage (transmission) System
CPUC	California Public Utilities Commission
CRO	Contingency Reserve Obligation
CRPP	Comprehensive Reliability Planning Process (of NYISO)
DADRP	Day-Ahead Demand Response Program
dc	Direct Current
DCLM	Direct Controlled Load Management
DFW	Dallas/Fort Worth
DLC	Direct Load Control
DOE	U.S. Department of Energy
DSG	Dynamics Study Group
DSI	Direct-served Industry
DSM	Demand -side Management
DVAR	D-VAR® reactive power compensation system
EDRP	Emergency Demand Response Program
EEA	Energy Emergency Alert
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Agency (of DOE)
EILS	Emergency Interruptible Load Service (of ERCOT)
EISA	Energy Independence and Security Act of 2007 (USA)
ELCC	Effective Load-carrying Capability
EMTP	Electromagnetic Transient Program
ENS	Energy Not Served
EOP	Emergency Operating Procedure
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FCITC	First Contingency Incremental Transfer Capability
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission

FP	Future Planned
FO	Future Other
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GGGS	Gerald Gentleman Station Stability
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool (of MAPP)
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
HVAC	Heating, Ventilating, and Air Conditioning
IA	Interchange Authority
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (in Ontario)
IOU	Investor Owned Utility
IPL/NRI	International Power Line/Northeast Reliability Interconnect Project
IPSI	Integrated Power System Plan
IRM	Installed Reserve Margin
IROL	Interconnection Reliability Operating Limit
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LaaRs	Loads acting as a Resource
LCR	Locational Installed Capacity Requirements
LDC	Load Duration Curve
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss Of Load Probability
LRP	Long Range Plan
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
LTSG	Long-term Study Group
MAAC	Mid-Atlantic Area Council
Maf	Million acre-feet
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCRSG	Midwest Contingency Reserve Sharing Group
MISO	Midwest Independent Transmission System Operator
MPRP	Maine Power Reliability Program
MRO	Midwest Reliability Organization
MVA	Megavolt amperes
Mvar	Mega-vars
MW	Megawatts (millions of watts)
MWEX	Minnesota Wisconsin Export
NB	New Brunswick
NBSO	New Brunswick System Operator

NDEX	North Dakota Export Stability Interface
NEEWS	New England East West Solution
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NOPSG	Northwest Operation and Planning Study Group
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NSPI	Nova Scotia Power Inc.
NTSG	Near-term Study Group
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
NYPA	New York Planning Authority
NYRSC	New York State Reliability Council, LLC
NYSERDA	New York State Energy and Research Development Agency
OASIS	Open Access Same Time Information Service
OATT	Open Access Transmission Tariff
OP	Operating Procedure
OPA	Ontario Power Authority
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
OTC	Operating Transfer Capability
OVEC	Ohio Valley Electric Corporation
PA	Planning Authority
PACE	PacifiCorp East
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PCAP	Pre-Contingency Action Plans
PCC	Planning Coordination Committee (of WECC)
PJM	PJM Interconnection
PRB	Powder River Basin
PRC	Public Regulation Commission
PRSG	Planned Reserve Sharing Group
PSA	Power Supply Assessment
PUCN	Public Utilities Commission of Nevada
QSE	Qualified Scheduling Entities
RA	Resource Adequacy
RAP	Remedial Action Plan
RAR	Resource Adequacy Requirement
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RGGI	Regional Greenhouse Gas Initiative
RIS	Resource Issues Subcommittee of NERC Planning Committee
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
RP	Reliability Planner

RPM	Reliability Pricing Mode
RRS	Reliability Review Subcommittee
RSG	Reserve Sharing Group
RTEP	Regional Transmission Expansion Plan (for PJM)
RTO	Regional Transmission Organization
RTP	Real Time Pricing
RTWG	Renewable Technologies Working Group
SA	Security Analysis
SasKPower	Saskatchewan Power Corp.
SCADA	Supervisory Control and Data Acquisition
SCC	Seasonal Claimed Capability
SCD	Security Constrained Dispatch
SCDWG	Short Circuit Database Working Group
SCEC	State Capacity Emergency Coordinator (of FRCC)
SCR	Special Case Resources
SEMA	Southeastern Massachusetts
SEPA	State Environmental Protection Administration
SERC	SERC Reliability Corporation
SMUD	Sacramento Municipal Utility District
SOL	System Operating Limits
SPP	Southwest Power Pool
SPS	Special Protection System
SRIS	System Reliability Impact Studies
SRWG	System Review Working Group
STATCOM	Static Synchronous Compensator
STEP	SPP Transmission Expansion Plan
SVC	Static Var Compensation
TCF	Trillion Cubic Feet
TFCP	Task Force on Coordination of Planning
THI	Temperature Humidity Index
TIC	Total Import Capability
TID	Total Internal Demand
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPL	Transmission Planning
TRE	Texas Regional Entity
TRM	Transmission Reliability Margins
TS	Transformer Station
TSP	Transmission Service Provider
TSS	Technical Studies Subcommittee
TVA	Tennessee Valley Authority
USBRLC	United States Bureau of Reclamation Lower Colorado Region
UFLS	Under Frequency Load Shedding Schemes
UVLS	Under Voltage Load-Shedding
VACAR	Virginia and Carolinas (subregion of SERC)
VSAT	Voltage Stability Assessment Tool
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index
WUMS	Wisconsin-Upper Michigan Systems

Reliability Concepts Used in This Report

Demand Definitions[94]

Total Internal Demand: Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).

Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Demand Response Categorization

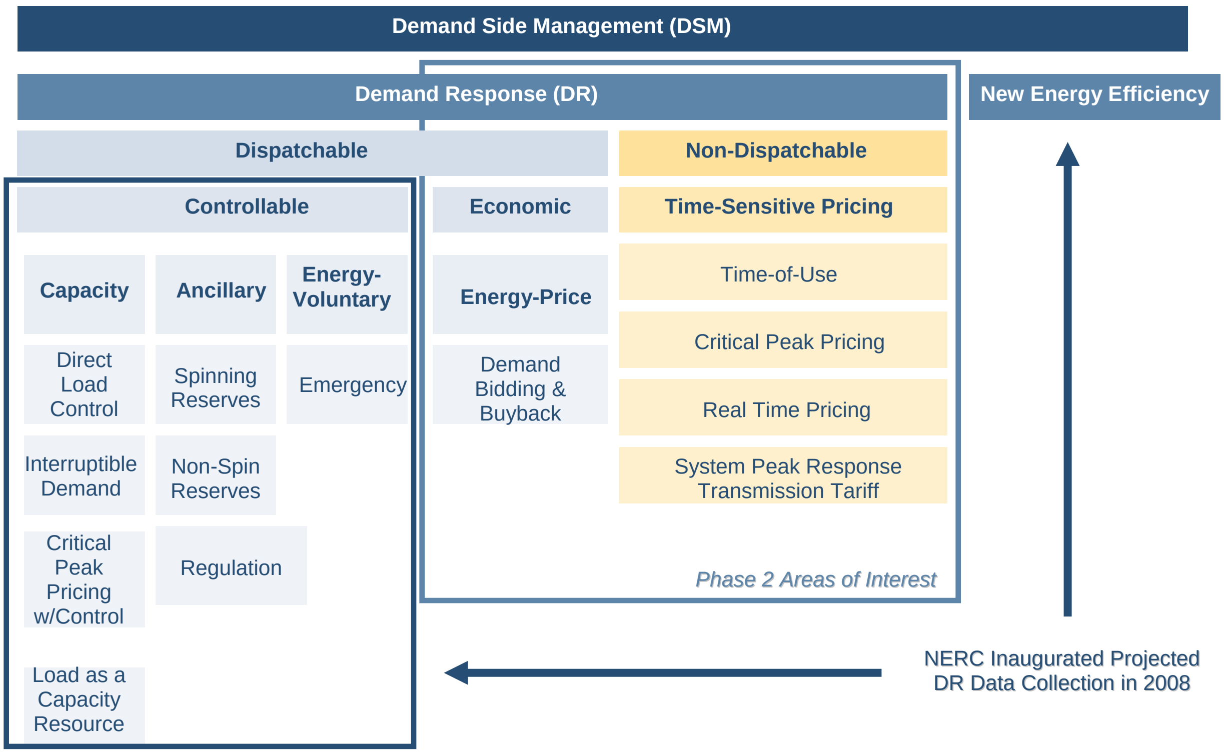
As the industry's use of Demand-Side Management evolves, NERC's data collection and reliability assessment need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected EE programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect demand response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Demand Side Management involves all activities or programs undertaken to influence the amount and timing of electricity use (See Figure 17).

Note the context of the definitions is demand-side management, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. The demand response categories defined below support Figure 17.

[94] For further information, refer to NERC's Reliability Assessments Guidebook at http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf

Figure 17: Demand-Side Management and NERC's Data Collection



Energy Efficiency: permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Demand Response: changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized

Dispatchable: demand-side resource curtails according to instruction from a control center

Controllable: dispatchable demand response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints

Capacity: demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance

Direct Control Load Management (DCLM): demand-side management that is under direct remote control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.[95]

Contractually Interruptible (Curtailable): curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Critical Peak Pricing (CPP) with Control: demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Load as a Capacity Resource: demand-side resources that commit to pre-specified load reductions when system contingencies arise.[96]

Ancillary: demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Non-Spin Reserves: demand-side resource not connected to the system but capable of serving demand within a specified time.

Spinning/Responsive Reserves: demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

Regulation: demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Energy-Voluntary: demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

Emergency: demand-side resource curtails during system and/or local capacity constraints.

Economic: Demand-side resource that is dispatched based on an economic decision.

Energy-Price: Demand-side resource that reduces energy for incentives.

Demand Bidding & Buyback: demand-side resource that enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

Non-dispatchable: demand-side resource curtails according to tariff structure, not instruction from a control center.

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[95] DCLM is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

[96] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning reserve margins.

Time-Sensitive Pricing: retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods.

Time-of-Use (TOU): rate and/or price structures with different unit prices for use during different blocks of time.

Critical Peak Pricing (CPP): rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Real Time Pricing (RTP): rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

System Peak Response Transmission Tariff: rate and /or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Capacity, Transaction and Margin Categories

<u>**Capacity Categories**</u>

I. Existing Generation Resources

I.A. - Existing, Certain — Existing generation resources available to operate and deliver power within or into the region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

- Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
- Where organized markets exist, designated market resource[97] that is eligible to bid into a market or has been designated as a firm network resource.
- Network Resource [98], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
- Energy-only resources [99] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[100]
- Capacity resources that can not be sold elsewhere.

[97] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[98] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[99] Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.
[100] Energy only resources with transmission service constraints are to be considered in category I.B.

- Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[101] during the period of analysis in the assessment.

I.B. - Existing, Other — Existing generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in I.A. This category includes, but is not limited to the following:

- A resource with non-firm or other similar transmission arrangements.
- Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
- Mothballed generation (that may be returned to service for the period of the assessment).
- Portions of variable generation not counted in the I.A. category (e.g., wind, solar, etc. that may not be available or derated during the assessment period).
- Hydro generation not counted as I.A. or derated.
- Generation resources constrained for other reasons.

I.C. - Existing, but Inoperable — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories I.A. or I.B., but is not limited to, the following:

- Mothballed generation (that can not be returned to service for the period of the assessment).
- Other existing but out-of-service generation (that can not be returned to service for the period of the assessment).
- This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
- This category does not include partially dismantled units that are not forecasted to return to service.

II. Future Generation Resources

This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

- Construction has started.
- Regulatory permits being approved, any one of the following:
    - Site permit
    - Construction permit
    - Environmental permit
- Regulatory approval has been received to be in the rate base.

[101] Energy only resources with transmission service constraints are to be considered in category I.B.

- Approved power purchase agreement.
- Approved and/or designated as a resource by a market operator.

II.A. - Future, Planned —Generation resources anticipated to be available to operate and deliver power within or into the region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

- Contracted (or firm) or other similar resource.
- Where organized markets exist, designated market resource[102] that is eligible to bid into a market or has been designated as a firm network resource.
- Network Resource [103], as that term is used for FERC pro forma or other regulatory approved tariffs.
- Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[104]
- Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

II.B. - Future, Other – this category includes future generating resources that do not qualify in II.A. and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

- Be curtailed or interrupted at any time for any reason.
- Energy-only resources that may not be able to serve load during the period of analysis in the assessment.
- Variable generation not counted in the II.A. category or may not be available or is derated during the assessment period.
- Hydro generation not counted in category II.A. or derated.
- Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Transaction Categories

Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one region and sold to another region, the region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside region. The purchasing region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

The following are categories of Purchases/Imports and Sales/Exports contracts:

[102] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[103] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[104] Energy only resources with transmission service constraints are to be considered in category II.B

I. **Firm**

(1) Firm implies a contract has been signed and may be recallable.

(2) Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

II. **Non-Firm**

(1) Non-Firm implies a non-firm contract has been signed.

(2) Non-Firm Purchases and Sales should not be considered in the reliability assessments.

III. **Expected**

(1) Expected implies that a contract has not been executed, but in negotiation, projected or other. These Purchases or Sales are expected to be firm.

(2) Expected Purchases and Sales should be considered in the reliability assessments.

IV. **Provisional**

(1) Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally firm.

(2) Provisional Purchases and Sales should be considered in the reliability assessments.

Margin Categories

Existing, Certain & Net Firm Transactions (MW) –
Existing, Certain capacity resources plus Firm Imports, minus Firm Exports.

Deliverable Capacity Resources (MW) –
Existing, Certain & Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports.

Prospective Capacity Resources (MW) –
Deliverable Capacity Resources plus Existing, Other capacity resources, minus all Existing, Other deratings (Includes derates from variable resources, energy only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future, Other capacity resources, minus all Future, Other deratings.

Existing-Certain and Net Firm Transactions (%) –
Existing, Certain & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Deliverable Capacity Reserve Margin (%) –
Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Prospective Capacity Reserve Margin (%) –
Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Target Reserve Margin (%) — Established target for reserve margin by the region or subregion. Not all regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the region/subregion or NERC assigned based on capacity mix (i.e. thermal/hydro). *Each region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned 15 percent reserve margin for predominately thermal systems and for predominately hydro systems, 10 percent.*

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects[105]:

Adequacy — is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Operating Reliability — is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding Adequacy, system operators can and should take “controlled” actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand — demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.[106]
- Voltage reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts — the term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

[105] See http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf more information about the Adequate Level of Reliability (ALR).

[106] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" — the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a "rotating blackout" or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

Capacity Margin to Reserve Margin Changes

Background[107]

The term reserve margin is widely used throughout the power industry. However, the word "reserve" engendered much misunderstanding on the part of policy makers. Therefore, the NERC Board of Trustees adopted the use of "capacity margin" to measure supply adequacy in 1984. Although NERC adopted the term capacity margin (25 years ago), the majority of the power industry continues to use "reserve margin."

Discussion

The Reliability Assessment Subcommittee (RAS) has reviewed the use of reserve margin and capacity margin terms. Both terms are used throughout the Long-Term Reliability Assessment (LTRA) and seasonal reliability assessments. This multiple use has caused significant confusion to the readers. For example, during Florida's recent disturbance event, an article (published by US News & World Report on 2/26/2008) made the incorrect assumption that capacity margin was the same as reserve margin. In addition, the majority, if not all, of the State Public Service Commissions continue to use the metric "reserve margin."

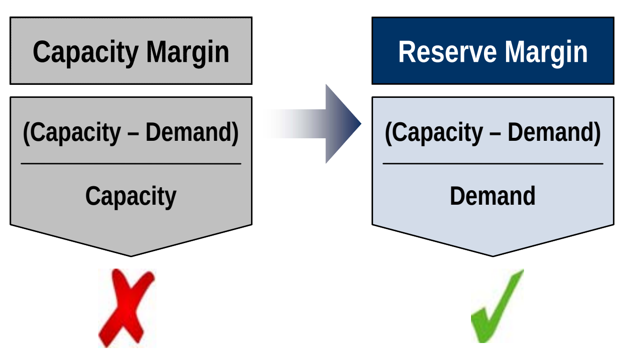
In a recent survey conducted by the Resource Issues Subcommittee (RIS), 29 of 38 Planning Authorities (PA) perform their work relying on "reserve margin." In contrast, only one PA referenced "Capacity Margin." The same survey shows that five of eight Regional Entities reference "reserve margin" as the metric they use to measure resource adequacy and while none reference "capacity margin."

Since the audience of NERC's assessments consists of a wide range of readers (including state and local regulatory bodies), industry terms should be consistent. NERC's goal is to convey reliability assessments in a way that reduces confusion. Since NERC's focus is to maintain bulk power system reliability in order to serve customer load and therefore, it is appropriate to express resource margins normalized by customer load ("reserve margin").

Approval

Upon recommendations from the RAS and RIS, the PC approved the use of "reserve margin" in place of "capacity margin," on December 3, 2008 for all future reliability assessments, beginning with reliability assessments in 2009.

Figure: Reserve Margin to be Used for Future NERC Reliability Assessments



[107] http://www.nerc.com/docs/pc/Updated_PC_Agenda_3-4Dec2008.doc

Capacity Margins for 2009 Summer Reliability Assessment Data

Tables 5a through 5b present 2009 data with *capacity* margins calculated in the same manner as 2008 and prior years. These tables are provided herein for reference. These tables are similar in format to Tables 4a through 4b in the *Estimated Demand, Resources, and Reserve Margins* Section of this report to facilitate comparison.

For Tables 5a through 5b, the following definitions apply.[108]

Existing-Certain and Net Firm Transactions (%) — Existing, Certain, and Net Firm Transactions minus Net Internal Demand shown as a percent of Existing-Certain and Net Firm Transactions.

Deliverable Capacity Margin (%) — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Deliverable Capacity Resources.

Prospective Capacity Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Prospective Capacity Resources.

NERC Reference Capacity Margin Level (%) — Either the Target Capacity Margin provided by the region/subregion or NERC assigned based on capacity mix (i.e. thermal/hydro). *Each region/subregion may have their own specific capacity margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Capacity Margin level is adopted as the NERC Reference Capacity Margin Level. If not, NERC assigned 13 percent capacity margin for predominately thermal systems and for predominately hydro systems, 9 percent.*

[108] In Tables 5a-5d, the **bold** and *boxed* section represents the changes in margin calculation between reserve to capacity margins.

Table 5a: Estimated June 2009 Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable CAPACITY Margin (%)	Prospective CAPACITY Margin (%)	NERC Reference (CAPACITY) Margin Level (%)
United States									
ERCOT	57,041	55,926	68,951	70,250	70,250	18.9%	20.4%	20.4%	11.1%
FRCC	43,592	40,424	50,522	51,885	51,885	20.0%	22.1%	22.1%	13.0%
MRO	41,097	38,266	47,559	48,867	48,868	19.5%	21.7%	21.7%	13.0%
NPCC	58,022	54,257	70,209	72,753	72,910	22.7%	25.4%	25.6%	13.0%
New England	24,570	24,570	33,475	33,607	33,764	26.6%	26.9%	27.2%	13.0%
New York	33,452	29,687	36,734	39,146	39,146	19.2%	24.2%	24.2%	13.0%
RFC	166,200	158,000	213,100	213,100	214,400	25.9%	25.9%	26.3%	13.0%
RFC-MISO	57,900	56,200	70,800	70,800	72,100	20.6%	20.6%	22.1%	13.0%
RFC-PJM	108,200	101,700	142,300	142,300	142,300	28.5%	28.5%	28.5%	13.0%
SERC	186,157	180,242	242,221	242,223	255,768	25.6%	25.6%	29.5%	13.0%
Central	39,451	37,800	51,026	51,028	52,673	25.9%	25.9%	28.2%	13.0%
Delta	25,567	24,902	38,735	38,735	38,954	35.7%	35.7%	36.1%	13.0%
Gateway	16,499	16,399	20,857	20,857	20,857	21.4%	21.4%	21.4%	13.0%
Southeastern	45,784	44,069	57,949	57,949	67,704	24.0%	24.0%	34.9%	13.0%
VACAR	58,856	57,072	73,654	73,654	75,580	22.5%	22.5%	24.5%	13.0%
SPP	40,223	39,456	49,298	49,719	55,886	20.0%	20.6%	29.4%	13.0%
WECC	130,198	126,030	169,992	171,733	171,733	25.9%	26.6%	26.6%	12.1%
AZ-NM-SNV	28,170	27,551	36,259	36,451	36,451	24.0%	24.4%	24.4%	11.7%
CA-MX US	54,579	51,853	64,445	65,658	65,658	19.5%	21.0%	21.0%	13.3%
NWPP	36,883	36,343	56,436	56,486	56,486	35.6%	35.7%	35.7%	11.9%
RMPA	10,566	10,283	12,812	13,112	13,112	19.7%	21.6%	21.6%	10.5%
Total-U.S.	722,530	692,601	911,852	920,530	941,700	24.0%	24.8%	26.5%	13.0%
Canada									
MRO	6,245	5,972	7,330	8,103	8,103	18.5%	26.3%	26.3%	9.0%
NPCC	48,504	48,069	61,788	62,805	64,456	22.2%	23.5%	25.4%	13.0%
Maritimes	3,571	3,136	5,684	5,684	5,684	44.8%	44.8%	44.8%	13.0%
Ontario	24,058	24,058	25,237	26,153	27,649	4.7%	8.0%	13.0%	14.5%
Quebec	20,875	20,875	30,867	30,968	31,123	32.4%	32.6%	32.9%	9.1%
WECC	17,486	17,484	22,112	22,397	22,397	20.9%	21.9%	21.9%	10.2%
Total-Canada	72,235	71,525	91,230	93,305	94,956	21.6%	23.3%	24.7%	13.0%
Mexico									
WECC CA-MX Mex	1,972	1,972	2,288	2,288	2,288	13.8%	13.8%	13.8%	12.5%
Total-NERC	796,737	766,098	1,005,370	1,016,123	1,038,944	23.8%	24.6%	26.3%	13.0%

Table 5b: Estimated July 2009 Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable CAPACITY Margin (%)	Prospective CAPACITY Margin (%)	NERC Reference (CAPACITY) Margin Level (%)
United States									
ERCOT	60,618	59,503	69,881	72,362	72,362	14.9%	17.8%	17.8%	11.1%
FRCC	45,091	41,914	50,908	52,271	52,271	17.7%	19.8%	19.8%	13.0%
MRO	43,539	40,641	47,514	48,815	48,837	14.5%	16.7%	16.8%	13.0%
NPCC	61,327	57,562	70,232	72,872	73,029	18.0%	21.0%	21.2%	13.0%
New England	27,875	27,875	33,475	33,703	33,860	16.7%	17.3%	17.7%	13.0%
New York	33,452	29,687	36,757	39,169	39,169	19.2%	24.2%	24.2%	13.0%
RFC	178,100	169,900	213,100	213,100	214,400	20.3%	20.3%	20.8%	13.0%
RFC-MISO	61,800	60,100	70,800	70,800	72,100	15.1%	15.1%	16.6%	13.0%
RFC-PJM	116,200	109,700	142,300	142,300	142,300	22.9%	22.9%	22.9%	13.0%
SERC	201,364	195,211	243,309	243,311	257,066	19.8%	19.8%	24.1%	13.0%
Central	42,733	40,874	50,645	50,647	52,290	19.3%	19.3%	21.8%	13.0%
Delta	26,989	26,319	38,727	38,727	38,975	32.0%	32.0%	32.5%	13.0%
Gateway	19,065	18,946	20,663	20,663	20,699	8.3%	8.3%	8.5%	13.0%
Southeastern	49,009	47,294	59,364	59,364	69,117	20.3%	20.3%	31.6%	13.0%
VACAR	63,568	61,778	73,910	73,910	75,985	16.4%	16.4%	18.7%	13.0%
SPP	43,794	43,027	49,298	49,719	55,886	12.7%	13.5%	23.0%	13.0%
WECC	140,852	136,562	171,743	173,439	173,439	20.5%	21.3%	21.3%	12.1%
AZ-NM-SNV	30,505	29,896	36,241	36,419	36,419	17.5%	17.9%	17.9%	11.7%
CA-MX US	59,103	56,306	64,834	67,313	67,313	13.2%	16.4%	16.4%	13.3%
NWPP	39,740	39,141	57,815	56,568	56,568	32.3%	30.8%	30.8%	11.9%
RMPA	11,504	11,219	12,813	13,113	13,113	12.4%	14.4%	14.4%	10.5%
Total-U.S.	774,685	744,320	915,985	925,889	947,290	18.7%	19.6%	21.4%	13.0%
Canada									
MRO	6,382	6,109	7,510	8,276	8,276	18.7%	26.2%	26.2%	9.0%
NPCC	49,211	48,772	65,609	67,487	68,282	25.7%	27.7%	28.6%	13.0%
Maritimes	3,513	3,074	5,671	5,671	5,671	45.8%	45.8%	45.8%	13.0%
Ontario	24,998	24,998	28,010	29,787	30,409	10.8%	16.1%	17.8%	14.5%
Quebec	20,700	20,700	31,928	32,029	32,202	35.2%	35.4%	35.7%	9.1%
WECC	18,071	18,071	23,227	23,484	23,484	22.2%	23.0%	23.1%	10.2%
Total-Canada	73,664	72,952	96,346	99,247	100,042	24.3%	26.5%	27.1%	13.0%
Mexico									
WECC CA-MX Mex	2,084	2,084	2,287	2,387	2,387	8.9%	12.7%	12.7%	12.5%
Total-NERC	850,433	819,356	1,014,618	1,027,522	1,049,720	19.2%	20.3%	21.9%	13.0%

Table 5c: Estimated August 2009 Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable CAPACITY Margin (%)	Prospective CAPACITY Margin (%)	NERC Reference (CAPACITY) Margin Level (%)
United States									
ERCOT	64,218	63,103	70,626	73,107	73,107	10.7%	13.7%	13.7%	11.1%
FRCC	45,734	42,531	50,510	51,873	51,873	15.8%	18.0%	18.0%	13.0%
MRO	43,431	40,505	47,523	48,824	48,846	14.8%	17.0%	17.1%	13.0%
NPCC	61,327	57,562	70,210	72,850	73,007	18.0%	21.0%	21.2%	13.0%
New England	27,875	27,875	33,475	33,703	33,860	16.7%	17.3%	17.7%	13.0%
New York	33,452	29,687	36,735	39,147	39,147	19.2%	24.2%	24.2%	13.0%
RFC	172,600	164,400	213,100	213,100	214,400	22.9%	22.9%	23.3%	13.0%
RFC-MISO	62,500	60,800	70,800	70,800	72,100	14.1%	14.1%	15.7%	13.0%
RFC-PJM	110,000	103,500	142,300	142,300	142,300	27.3%	27.3%	27.3%	13.0%
SERC	200,265	194,155	243,706	243,708	257,505	20.3%	20.3%	24.6%	13.0%
Central	41,968	40,174	50,629	50,631	52,270	20.7%	20.7%	23.1%	13.0%
Delta	27,865	27,170	39,203	39,203	39,493	30.7%	30.7%	31.2%	13.0%
Gateway	19,024	18,905	20,645	20,645	20,687	8.4%	8.4%	8.6%	13.0%
Southeastern	49,504	47,789	59,340	59,340	69,093	19.5%	19.5%	30.8%	13.0%
VACAR	61,904	60,117	73,889	73,889	75,962	18.6%	18.6%	20.9%	13.0%
SPP	44,342	43,575	49,298	49,719	55,886	11.6%	12.4%	22.0%	13.0%
WECC	141,019	136,768	170,664	172,353	172,353	19.9%	20.6%	20.6%	12.1%
AZ-NM-SNV	30,228	29,625	36,272	36,478	36,478	18.3%	18.8%	18.8%	11.7%
CA-MX US	61,237	58,421	64,861	67,358	67,358	9.9%	13.3%	13.3%	13.3%
NWPP	38,421	37,876	56,680	55,380	55,380	33.2%	31.6%	31.6%	11.9%
RMPA	11,133	10,846	12,810	13,110	13,110	15.3%	17.3%	17.3%	10.5%
Total-U.S.	772,937	742,600	915,637	925,534	946,978	18.9%	19.8%	21.6%	13.0%
Canada									
MRO	6,325	6,052	7,588	8,354	8,354	20.2%	27.6%	27.6%	9.0%
NPCC	48,677	48,233	64,588	66,466	67,339	25.3%	27.4%	28.4%	13.0%
Maritimes	3,497	3,053	5,733	5,733	5,733	46.8%	46.8%	46.8%	13.0%
Ontario	24,192	24,192	28,206	29,983	30,687	14.2%	19.3%	21.2%	14.5%
Quebec	20,988	20,988	30,649	30,750	30,919	31.5%	31.7%	32.1%	9.1%
WECC	17,730	17,730	23,321	23,578	23,578	24.0%	24.8%	24.8%	10.2%
Total-Canada	72,732	72,015	95,497	98,398	99,271	24.6%	26.8%	27.5%	13.0%
Mexico									
WECC CA-MX Mex	2,115	2,115	2,287	2,437	2,437	7.5%	13.2%	13.2%	12.5%
Total-NERC	847,783	816,729	1,013,421	1,026,369	1,048,686	19.4%	20.4%	22.1%	13.0%

Table 5d: Estimated September 2009 Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable CAPACITY Margin (%)	Prospective CAPACITY Margin (%)	NERC Reference (CAPACITY) Margin Level (%)
United States									
ERCOT	50,407	49,292	70,292	72,818	72,818	29.9%	32.3%	32.3%	11.1%
FRCC	43,689	40,515	47,792	49,292	49,292	15.2%	17.8%	17.8%	13.0%
MRO	40,160	37,427	47,373	48,694	47,938	21.0%	23.1%	21.9%	13.0%
NPCC	55,522	51,757	64,590	67,230	67,387	19.9%	23.0%	23.2%	13.0%
New England	22,070	22,070	33,475	33,703	33,860	34.1%	34.5%	34.8%	13.0%
New York	33,452	29,687	31,115	33,527	33,527	4.6%	11.5%	11.5%	13.0%
RFC	152,600	144,400	213,100	213,100	214,400	32.2%	32.2%	32.6%	13.0%
RFC-MISO	53,200	51,500	70,800	70,800	72,100	27.3%	27.3%	28.6%	13.0%
RFC-PJM	99,300	92,800	142,300	142,300	142,300	34.8%	34.8%	34.8%	13.0%
SERC	182,987	177,111	240,043	240,045	253,674	26.2%	26.2%	30.2%	13.0%
Central	39,434	37,852	50,134	50,136	51,785	24.5%	24.5%	26.9%	13.0%
Delta	25,594	24,909	38,920	38,920	39,234	36.0%	36.0%	36.5%	13.0%
Gateway	16,017	15,917	20,911	20,911	20,911	23.9%	23.9%	23.9%	13.0%
Southeastern	45,469	43,755	58,318	58,318	68,073	25.0%	25.0%	35.7%	13.0%
VACAR	56,473	54,678	71,760	71,760	73,671	23.8%	23.8%	25.8%	13.0%
SPP	38,305	37,538	49,298	49,719	55,886	23.9%	24.5%	32.8%	13.0%
WECC	128,127	124,108	170,074	172,051	172,051	27.0%	27.9%	27.9%	12.1%
AZ-NM-SNV	27,187	26,587	36,192	36,386	36,386	26.5%	26.9%	26.9%	11.7%
CA-MX US	55,949	53,148	64,734	66,261	66,261	17.9%	19.8%	19.8%	13.3%
NWPP	35,240	34,801	56,755	56,725	56,725	38.7%	38.6%	38.6%	11.9%
RMPA	9,751	9,572	12,352	12,652	12,652	22.5%	24.3%	24.3%	10.5%
Total-U.S.	691,797	662,148	902,562	912,949	933,447	26.6%	27.5%	29.1%	13.0%
Canada									
MRO	5,970	5,697	7,132	7,918	7,918	20.1%	28.0%	28.0%	9.0%
NPCC	46,410	45,956	60,570	62,501	64,065	24.1%	26.5%	28.3%	13.0%
Maritimes	3,629	3,175	5,676	5,676	5,676	44.1%	44.1%	44.1%	13.0%
Ontario	22,071	22,071	25,734	27,564	29,015	14.2%	19.9%	23.9%	14.5%
Quebec	20,710	20,710	29,160	29,261	29,374	29.0%	29.2%	29.5%	9.1%
WECC	17,435	17,418	21,899	22,465	22,465	20.5%	22.5%	22.5%	10.2%
Total-Canada	69,815	69,071	89,601	92,884	94,448	22.9%	25.6%	26.9%	13.0%
Mexico									
WECC CA-MX Mex	2,092	2,092	2,287	2,387	2,387	8.5%	12.4%	12.4%	12.5%
Total-NERC	763,704	733,311	994,450	1,008,220	1,030,282	26.3%	27.3%	28.8%	13.0%

Data Checking Methods Applied

NERC's Reliability Assessment Data Validation & Error Checking Program ensures that the Reliability Assessment Database operates with consistent data. It uses routines, often called "validation rules," that check for correctness, meaningfulness, and security of data that are added into the system.

Internal Data Checking & Validation refers to the practice of validating and checking data through internal processes (e.g., Historical Comparison, Range and Limits, Data Entry Completeness, Correct Summations) to maintain high quality data (See Table 6). The rules are implemented through automated processes—data dictionary for data checking and logic for validation. Incorrect data can lead to data corruption or a loss of data integrity. Data validation verifies it is valid, sensible, and secure before it is processed for analysis. The program uses scripts, developed on a composite Microsoft Excel and Microsoft Access platform, to provide a semi-automated solution.

Table 6: NERC Data Quality Framework and Attributes		
Data Quality Attribute	Responsible Entity	Data Check Performed
Accuracy *Ensure data are the correct values*	Industry	• Validation rules • Consistent with other external sources
Accessibility *Data items should be easily obtainable and in a usable format*	DCWG, NERC and RE	• Data is submitted in the provided template
Comprehensiveness *All required data items are submitted*	DCWG, RE and Stakeholders	• Check for null values • Compare to prior year's null values • Inquiries to the RE
Currency *The data should be up-to-date*	RE and Stakeholders	• Consistent with other external sources
Consistency *The value of the data should be reliable and the same across different reporting entities*	DCWG, NERC	• The DCWG leads in this effort • Assumptions are verified with the RE
Definition *Clear definitions should be provided so the current and future data users can understand the assumptions*	DCWG, NERC Staff	• The DCWG leads in this effort

In 2009, NERC implemented a two-phase approach to data checking and validation. Phase I is a data collection form-side validation procedure based on defined rules. It also specifies the error type or condition not met. This phase was applied to the data collection forms to prevent the incorrect entry of data and prompts the user with feedback explaining the error. Validation rules are used to ensure entered data meets defined thresholds, ranges, or both. An error halts the input of data until a valid entry is provided. For example, the reported deratings of existing generating units is a subset of the "Existing, Other" supply category; therefore, the sum of all deratings must be less than or equal to the value reported as "Existing, Other." This example is shown below:

		Incorrect	Correct
6b	**Existing, Other** (Note: The sum of 6b1 through 6b7 must be <= 6b)	5000	5000
6b1	Wind Derate On-Peak	800	400
6b2	Solar Derate On-Peak	445	232
6b3	Hydro Derate On-Peak	789	0
6b4	Biomass Derate On-Peak	0	0
6b5	Load as a Capacity Resource Derate On-Peak	0	0
6b6	Energy Only	435	1345
6b7	Scheduled Outage - Maintenance	4000	2398
6b8	Transmission-Limited Resources	0	0

Once data is submitted to NERC, reported values can be analyzed for validity. Phase II of NERC's data checking and validation effort involves comparing submitted data to historical submissions. For this phase, a back-end database is used to compare key values, such as peak demand projections and installed capacity to what was reported in prior years. Only values with comparable definitions are considered. In addition, a preliminary analysis can identify potential errors. If a potential error is detected, it is flagged and categorized by one of the following error types:

- Categorization – values may be incorrectly categorized
- Summation – values are incorrectly summed
- Double Count – identifies a possible double counting issue
- Missing Data – key values are null
- Confirmation – a notable discrepancy which must be confirmed

The Reliability Assessment Data Validation & Error Checking Program identifies potential errors and generates a report for further investigation. Thresholds are determined for each value and flagged when a major deviation is determined. For example, peak demand projections must be within a +/- 2 percent threshold to pass; all others are flagged. When errors are identified, NERC staff can send a request for data corrections to the Regional Entities. The Regional Entities then have the opportunity to update their data submittals or explain the flagged error.

In addition, NERC's Data Coordination Working Group (DCWG) monitors the quality of data reported. The DCWG serves as a point of contact responsible for supporting NERC staff, continuously maintaining high quality data and provide enhancements to current practices.

For the *2009 Summer Reliability Assessment*, the most common error identified was Missing Data, though in many cases "0" was the correct value. Summation errors were also prominent. Unclear form instructions and changes in reporting format may have contributed to these errors.

Report Content Responsibility

The following NERC industry groups have collaborated efforts to produce NERC's *2009 Summer Reliability Assessment*:

NERC Group	Relationship	Contribution
Planning Committee (PC)	Reports to NERC's Board of Trustees	• Review Assessment and Endorse
Operating Committee (OC)	Reports to NERC's Board of Trustees	• Review Assessment and provide comments to PC
Reliability Assessment Subcommittee (RAS)	Reports to the PC	• Peer Reviews • Review Report
Reliability Assessment Guidebook Task Force (RAGTF)	Reports to the PC	• Develop Reliability Assessment Guidebook
Data Coordination Working Group (DCWG)	Reports to the RAS	• Develop data and regional reliability narrative requests
Energy Ventures Analysis, Inc.	Third-Party Independent Consultant	• Provide assessment on North American natural gas and coal conditions
Board of Trustees	NERC's Independent Board	• Review Assessment • Approve for publication

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the reliability of the
bulk power system