NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2009 Long-Term Reliability Assessment

2009-2018

to ensure
the reliability of the
bulk power system

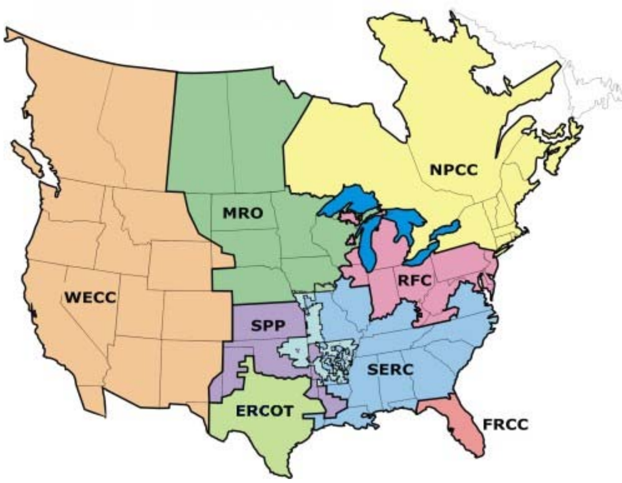
October 2009

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

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is 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 Terms Used in This Report and Reliability Concepts Used in this Report sections 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.

Table of Contents

Executive Summary

The reliable delivery of electricity to North American homes and businesses is a critical element of North Americans' way of life. Through the Energy Policy Act of 2005, the United States Congress charged the North American Electric Reliability Corporation (NERC) with developing annual long-term assessments of the reliability of the bulk power system. NERC is under similar obligations to many of the Canadian provinces.

NERC's annual ten-year reliability outlook, the *Long-Term Reliability Assessment*, provides an independent view of the reliability of the system, identifying trends, emerging issues, and potential concerns. NERC's projections are based on a bottom-up approach, collecting data and perspectives from grid operators, electric utilities, and other users, owners, and operators of the bulk power system. Improvements to the 2009 report include more extensive data validation and more granular data on generation and transmission.

Highlights of the 2009 report include:

Economic Recession, Demand-Side Management Lead to Decreased Demand, Higher Reserve Margins

Reduced economic activity and higher adoption of Demand-Side Management programs have led to decreased projected peak demand for electricity and, as a result, higher reserve margins throughout North America for much of the ten-year period. The increase in Demand-Side Management contributes to approximately 20 percent of the total reduction in summer peak demand for the 2017 forecast when compared to last year's forecast, while economic recession effects contribute 80 percent. While some Regions, including Texas, continue to see record peak demand, overall peak demand forecasts for 2009 have decreased by four percent from forecasts projected in 2008. Projected compound annual growth rate over the ten-year period for peak demand has also decreased overall, from 1.6 percent in 2008 projections to 1.5 percent in 2009 projections. Areas with the highest growth rates include the Desert Southwest (2.3 percent), the Southeastern subregion (2.2 percent), and Texas (2.1 percent). Areas with the lowest/negative growth rates include Ontario (-1.1 percent, due in part to aggressive energy efficiency programs), the Maritimes (.5 percent), and New York (.7 percent). The most significant change in projected peak demand occurs in Florida and the Northeast U.S. / Southeast Canada, where demand previously projected to be realized in 2010 is now not expected until 2015.

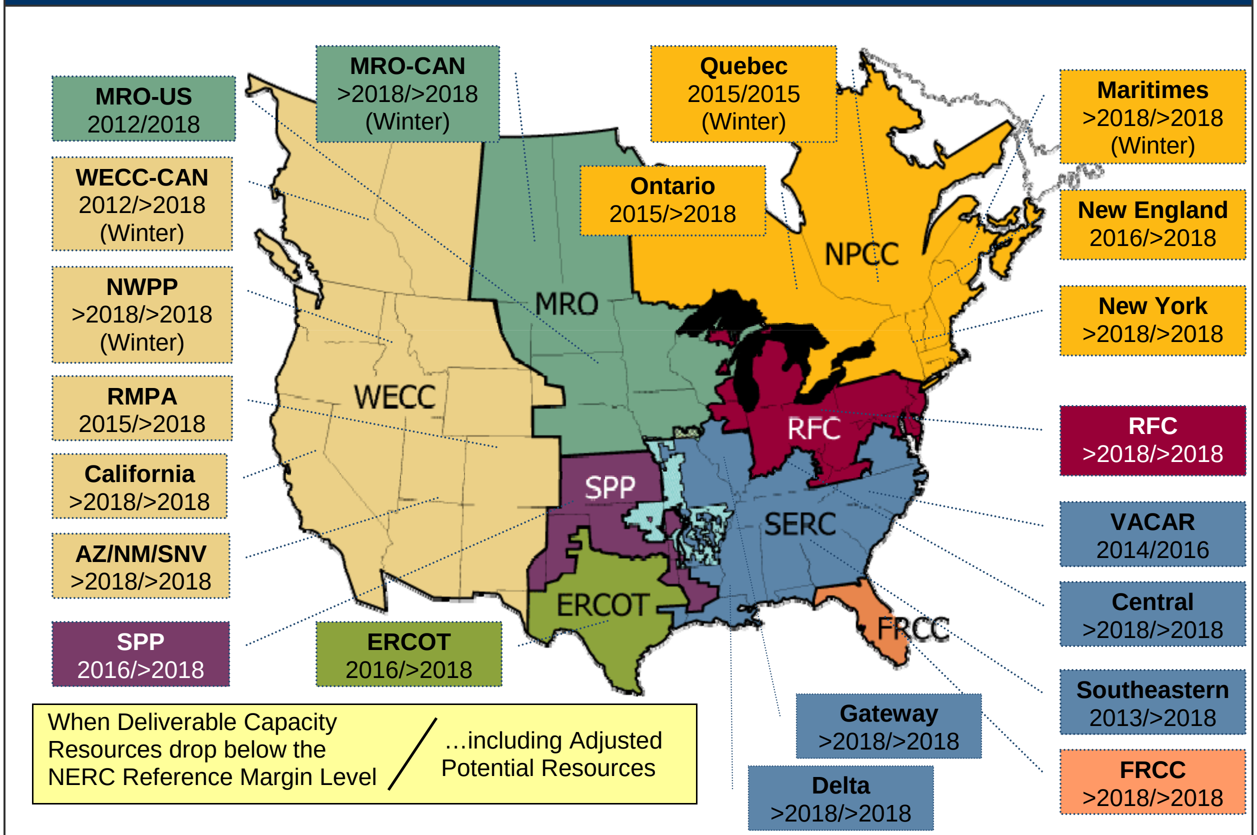
The use of Demand Response and Energy Efficiency programs in reliability planning continues to expand. Combined, these "demand-side resources" account for roughly 40,000 MW (or four percent) of the peaking resource portfolio, effectively offsetting peak demand growth by nearly five years by 2018. Areas with the highest adoption of these programs in the U.S. include Florida, the Northeast and the Midwest. In Canada, Ontario in particular has set aggressive energy efficiency targets, resulting in an expected 2.3 percent reduction in projected demand over the ten-year period. As these resources account for a growing portion of the peak capacity mix, performance over time must be monitored and reliability assessed. NERC's Demand Response Availability Data System will provide meaningful metrics and feedback to system planners and operators beginning in 2011.

While decreased demand generally has positive implications for resource adequacy, operational challenges can arise due to surplus base-load generation conditions in some areas, particularly during periods of low demand and in areas of high wind penetration. In Ontario, such conditions required grid operators to reduce the output of the province's nuclear fleet in June 2009. Additional transmission capacity can provide system operators more options to move power out of surplus-base load conditions to areas of higher demand.

The pace and shape of economic recovery will dramatically influence actual load growth across North America over the ten-year period. Largely unpredictable economic conditions result in a degree of uncertainty in 2009 demand forecasts that is not typically seen in periods of more stable economic activity.

Two Regions are expected to fall below target reserve margins in the first five-year period – Western Canada (2012) and the Midwestern United States (2012). While new resources are expected in the coming years to ensure margins remain adequate throughout the ten-year period, NERC will be closely monitoring the situation in these two areas (Figure Summary 1).

Figure Summary 1: Prospective and Adjusted Potential Resources Reserve Margins Compared to NERC's Reference Margin Level

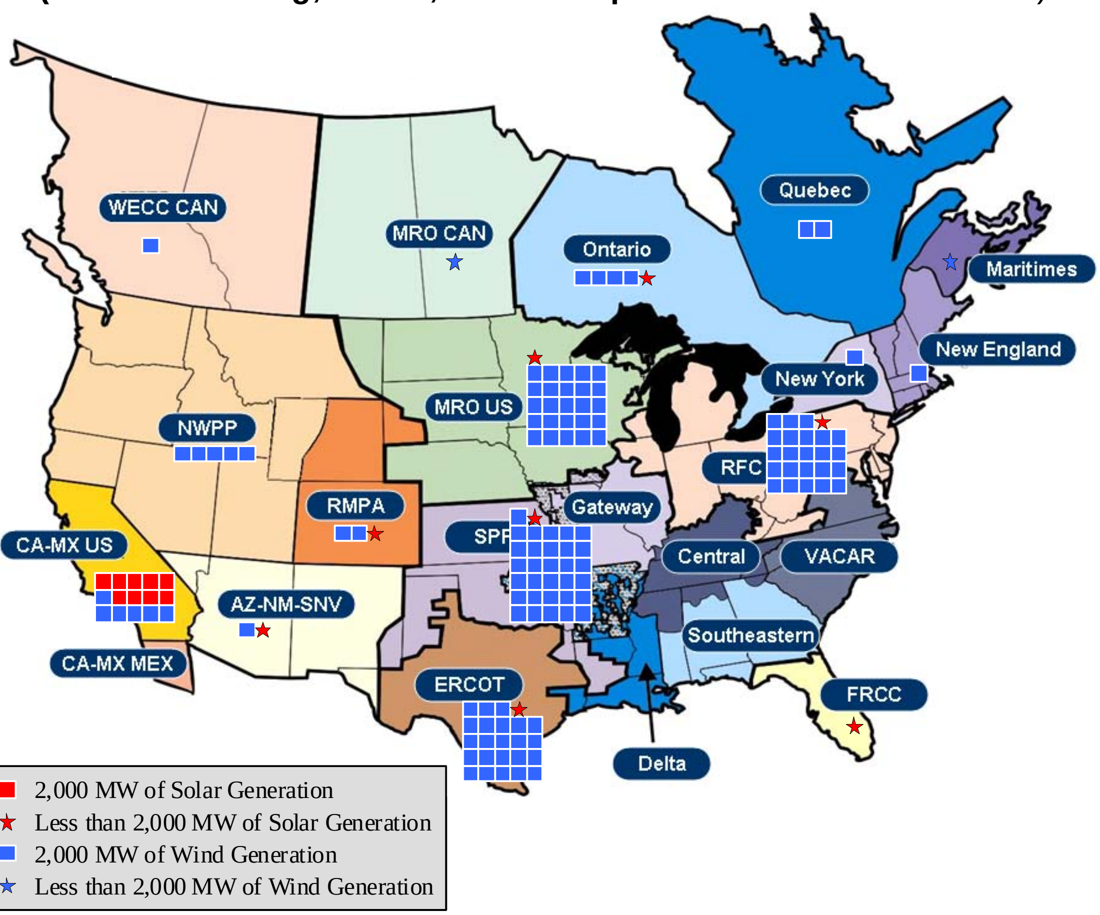


Note: NERC's Reference Margin Level represents either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (i.e., thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as 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.

Significant New Renewable Resources Come Online

Approximately 260,000 MW of new renewable "nameplate" capacity (biomass, geothermal, hydo, solar, and wind) is projected over the coming ten years. Roughly 96 percent of this total is comprised of wind (229,000 MW) and solar (20,000 MW), as shown in Figure Summary 2. Wind power alone is projected to account for 18 percent of the total resource mix by 2018. Due to its limited availability during times of peak demand, however, wind power accounts for only about three percent (or 38,000 MW) of the peak resource mix. Though not all of these resources may come to fruition, the integration of this volume of "energy-dominant" resources (or those resources predominately available during off-peak hours) will require significant changes to traditional planning and operating techniques to ensure reliability.

Figure Summary 2: 2018 Variable Generation Capacity (Includes Existing, Future, and Conceptual Generation Resources)



Note: The Conceptual wind and solar capacity projections for WECC subregions reflect the Balancing Authorities'' knowledge of such projects. These projections may be less than publicly available interconnection project queues within the Region.

Transmission and "flexible" resources — those fast-acting resources able to complement the significant ramps in availability associated with wind power — will be key components of any successful integration approach. In fact, it appears that growth in renewables and growth in transmission are positively correlated, as those areas with the highest projected growth in renewables are also those with the highest percentage increase in transmission miles: the Midwestern United States, Texas, and California. However, industry, policymakers and regulators have significant work ahead of them to ensure that sufficient transmission is sited and built to enable the integration of projected renewable resources. As noted in WECC's Regional assessment, the development of transmission resources has been the limiting factor in the development of renewable resources in much of the Western United States. Additionally, changes to grid operation procedures will be needed to provide operational flexibility.

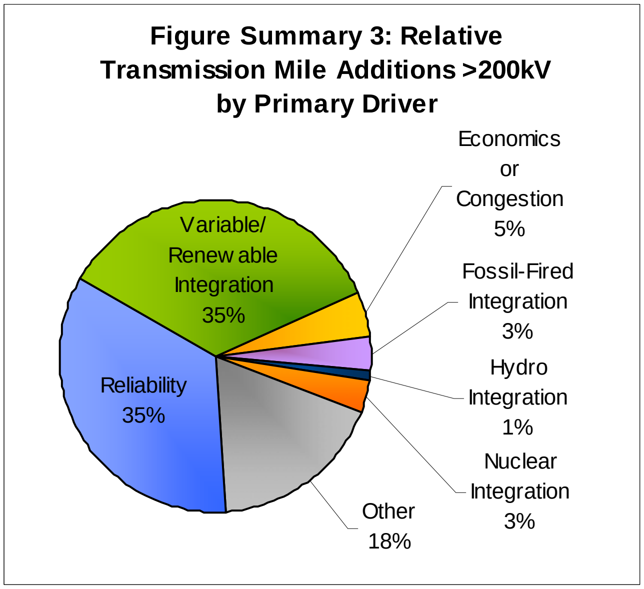
Natural Gas Expected to Replace Coal as the Leading Fuel for Peak Capacity by 2011

By 2011, natural gas is projected to overtake coal as the dominant fuel source for peak capacity generation in North America. By 2018, natural gas is projected to account for 32 percent of the on-peak resource mix. Natural gas-fired generation is typically easier to site, has shorter construction times, and has lower carbon emissions than other types of traditional generation, making it an attractive option for utilities and independent power producers. These competitive advantages have resulted in an overwhelming preference for the resource over the ten-year period, as installed natural gas capacity is projected to increase 38 percent over the ten-year period, while coal is projected to increase by only six percent. On-peak natural gas capacity is projected to grow by more than double the amount of any other resource, and by more than five times any other resource when dual fuel resources (primarily fired by natural gas and another, alternate fuel) are excluded. The projected growing reliance on natural gas increases the potential for adverse reliability impacts due to fuel supply and storage and delivery infrastructure adequacy issues.

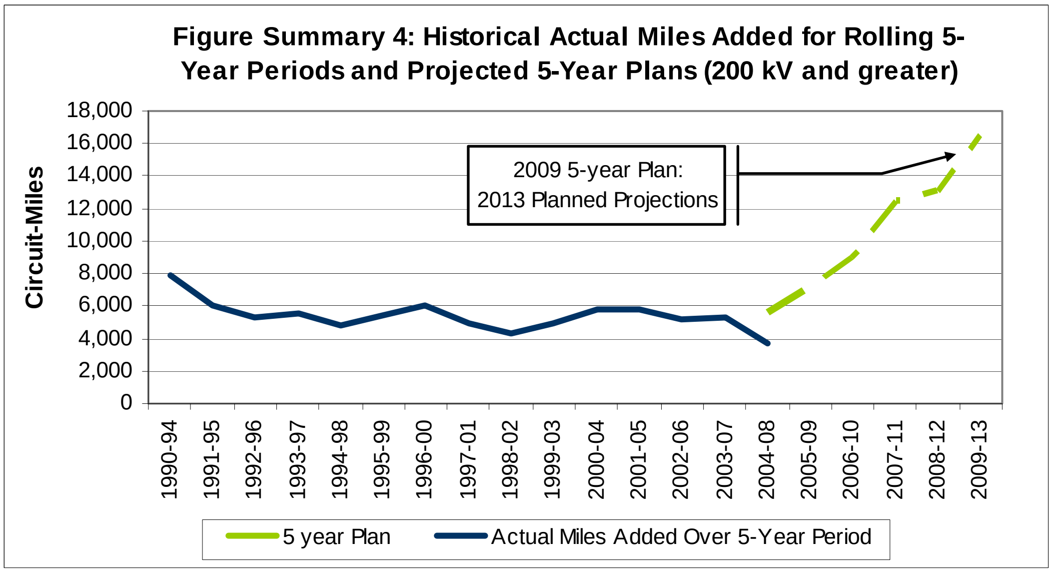
Concerns regarding the availability and deliverability of natural gas have diminished during 2009 as North American production has begun to trend upward due to a shift toward unconventional gas production from shale, tight sands, and coal-bed methane reservoirs. In its latest biennial assessment, the Potential Gas Committee increased U.S. natural gas resources by nearly 45 percent to 1,836 TCF, largely because of increases in unconventional gas across many geographic areas. Pipeline capacity has similarly increased, by 15 BCFD in 2007 and 44 BCFD in 2008, with an increase of 35 BCFD expected in 2009. Storage capacity has also increased substantially. The current low price environment for natural gas, driven by global economic conditions poses some concern for gas production: as the number of drilling rigs has decreased by approximately 50 percent since 2008 as the industry attempts to restore equilibrium from an oversupplied condition in 2009.

Transmission Siting and Construction Must Accelerate to Meet Plans and Ensure Reliability

More than 11,000 miles (or 35 percent) of transmission (200 kV and above) proposed and projected in this report must be developed on time to ensure reliability over the next 5 years. 32,000 miles of transmission (200 kV and above) are projected for construction from 2009 to 2013 overall.

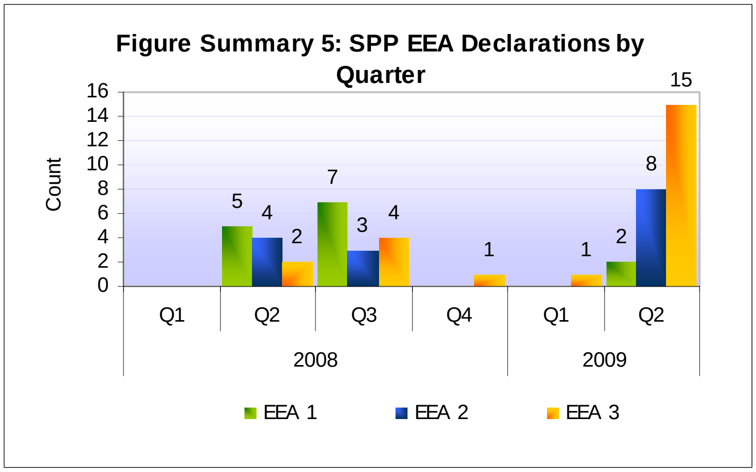


Constructing needed transmission facilities will require entities to more than double the average number of transmission-miles constructed over any five-year period since 1990 (Figure Summary 4). Ranked as the number one emerging issue in terms of likelihood and consequence, transmission siting remains a significant obstacle to meeting this goal. One 90-mile, 765 kV line, for example, took American Electric Power fourteen years to site and only two years to construct. State and provincial siting and permitting processes must be expedited to allow for the development of needed resources and ensure reliability.



Operational metrics indicate that SPP and SERC are already facing significant transmission constraints. Across North America, over 75 percent of the 49 level three Energy Emergency Alerts (EEA)[4] — reliability events called when firm load interruption is imminent or in progress — occurring between January 1, 2005 and July 15, 2009 were preceded by transmission loading relief requests.

A particular area of focus is SPP's Acadiana area, where 15 level three Energy Emergency Alerts were called as a result of a major generation outage in June 2009 (Figure Summary 5).[5] Plans are in place to address the issue through upgrades to the transmission system, but reliability in the area will remain dependent on continued use of EEA and other operational tools until the situation is resolved. NERC and SPP are closely monitoring the situation.



Industry Faces Transformational Change: Transmission Siting, Pending Climate Legislation, Integration of Variable Generation and Cyber Security Top List of Emerging Reliability Issues

Over the coming ten years, the North American electric industry will face a number of significant emerging reliability issues. The confluence of these issues will drive a transformational change for the industry, potentially resulting in a dramatically different resource mix, a new global market for emissions trading, a new model for customer interaction with their utility, and a new risk framework built to address growing cyber security concerns. Each of these elements of change are critically interdependent and industry action must be closely coordinated to ensure reliability. For this reason, NERC is paying considerable attention to these Emerging and Standing Issues.

Nine emerging issues were identified by industry, six of which are projected to be of high likelihood and high consequence by the end of the ten-year period: transmission siting, cyber security, climate legislation, variable generation issues, workforce issues, and reactive power (Figure Summary 6). All of these are real, critical, and growing issues that will be difficult to

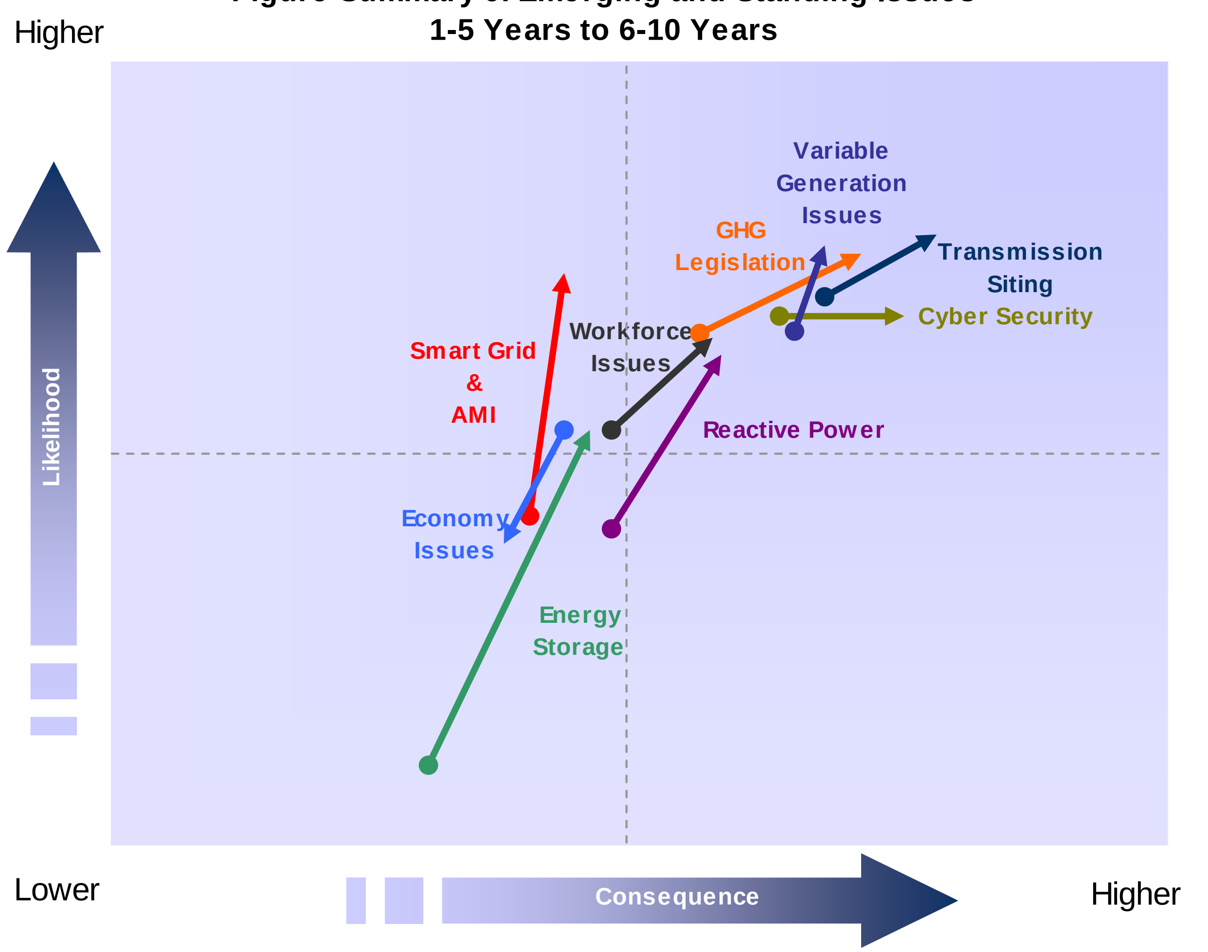
[4] These 49 alerts occurred between January 1, 2005 to July 15, 2009.

[5] In this case, additional transmission was determined to be the solution to alleviate transmission constraints; however, additional local generation or demand-side management may alleviate constraints in some cases.

solve, presenting a uniquely challenging outlook for this industry. Concerns relative to the economy are the only issue projected to decline in likelihood and consequence over the ten-year period.

The NERC Planning Committee has already formed groups to investigate the reliability impacts of climate change/greenhouse gas legislation, the integration of variable generation, smart grid, and reactive power. It is important for the industry to be informed and prepared for anything that may impact reliability in the future. While many of these issues are interrelated, each presents unique reliability considerations.

Figure Summary 6: Emerging and Standing Issues
1-5 Years to 6-10 Years

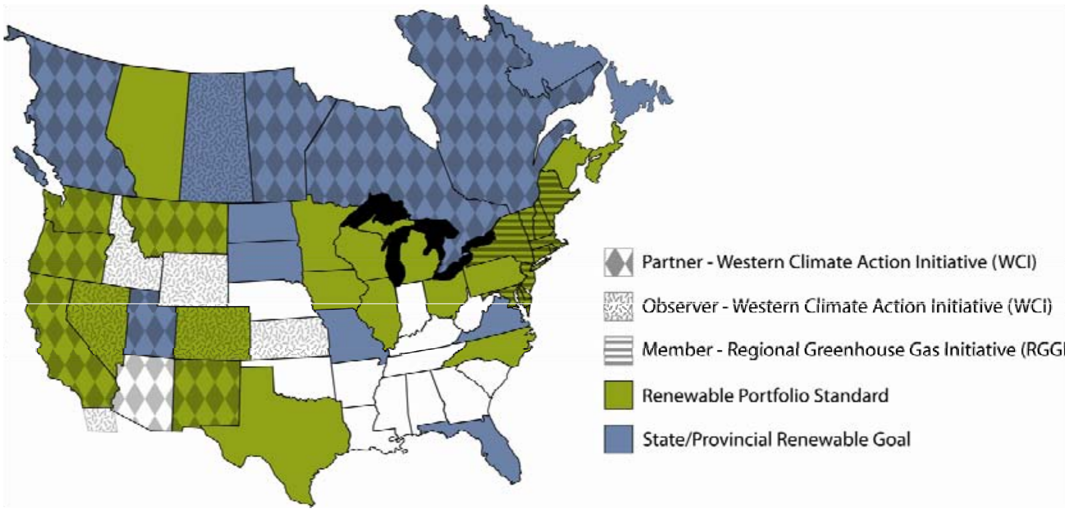


Note: The colors (of the arrows) in Figure Summary 6 were randomly chosen to differentiate overlapping arrows—the colors do not represent additional data or special meaning. Arrows point from the '1-5 Years' ranking to the '6-10 Years' ranking.

As discussed above, expediting the transmission siting process will be critical to the development of needed transmission resources during the ten-year period. The development of location-constrained renewable resources will largely depend on the industry's ability to site and construct the transmission needed to deliver power from these resources to demand centers.

Federal climate change legislation and state and provincial-level renewable portfolio standards are driving significant changes to the resource mix, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable resources (Figure Summary 7). Each of these factors will influence reliability over the ten-year period, requiring planners and operators to consider new factors in designing and operating the system of the future.

Figure Summary 7: Snapshot of North American Climate Change Initiatives



Cyber security is another important emerging issue facing all critical infrastructure sectors over the coming ten years. Addressing this issue will require a new way of looking at risk and vulnerability to the system, taking into account the potential for simultaneous impact to many assets across the system. The integration of new "Smart Grid" technologies will add additional complexity, as new access vectors are created to critical infrastructure components and systems. The increasing adoption of smart-grid-driven programs, potentially including demand response, advanced pricing, energy storage, rooftop solar, or plug-in hybrid electric vehicles, will make the adequate protection of these "distribution-level assets" vital to the reliability of the bulk power system in the years to come.

Progress Since 2008

In its *2008 Long-Term Reliability Assessment*,[6] NERC identified five *Key Findings* that could affect long-term reliability unless prompt actions were taken. NERC's key findings are based on observations and analyses of supply and demand projections submitted by the Regional Entities, NERC staff independent assessment, and other stakeholder input and comments.[7]

The magnitude of these issues necessitates complex planning and execution strategies whose impacts may not be realized for several years. As shown in Table 1, while some progress has been made, action is still needed on all of the issues identified in last year's report to ensure a reliable bulk power system for the future. Based on industry progress made on 2008 *Key Findings*, NERC either will continue to highlight them through the *Emerging and Standing Reliability Issues* section of this report, or will continue to monitor their advancement.

Table 1: Progress on 2008 Key Findings

2008 Key Finding	Progress in 2009	2009 Status
1. *Capacity Margins Improved, though Resources still Required*	Reserve Margins improve, primarily due to the economic recession forecast that reduces demand for several years. (See *Capacity Margin to Reserve Margin Changes* in this report for definitions.)	▪ *Reviewed in Estimated Planning Reserve Margins section*
2. *Wind Capacity Projected to Significantly Increase*	Wind capacity is projected to remain the largest source of capacity growth over the next decade (229,000 MW).	▪ *Reviewed in Generation section* ▪ *Standing Issue*
3. *More Transmission Needed to Maintain Bulk System Reliability and Integrate New Generation*	Significant additions of transmission are projected in the 2009 report to maintain reliability and support increases in variable generation located distant from demand centers.	▪ *Reviewed in Transmission section* ▪ *Emerging Issue*
4. *Demand Response Increasingly Used to Meet Resource Adequacy Requirements*	Demand Response projections continue to increase as markets develop and planners and operators rely upon it for resource adequacy and ancillary services.	▪ *Reviewed in Demand section* ▪ *Emerging Issue*
5. *Bulk Power System Adequacy Trends Emphasize Maintenance, Tools and Training*	Reliability Performance Trends developed to monitor operational and planning issues. Workforce Issues addressed as an Emerging Issue.	▪ *RMWG Report*[8] ▪ *Emerging Issue*

[6] http://www.nerc.com/files/LTRA2008v1_2.pdf

[7] Additional significant findings also appear in the *Regional Reliability Assessments*, *Operational Reliability* and *Emerging Issues Assessment and Scenario Analysis* sections of the report.

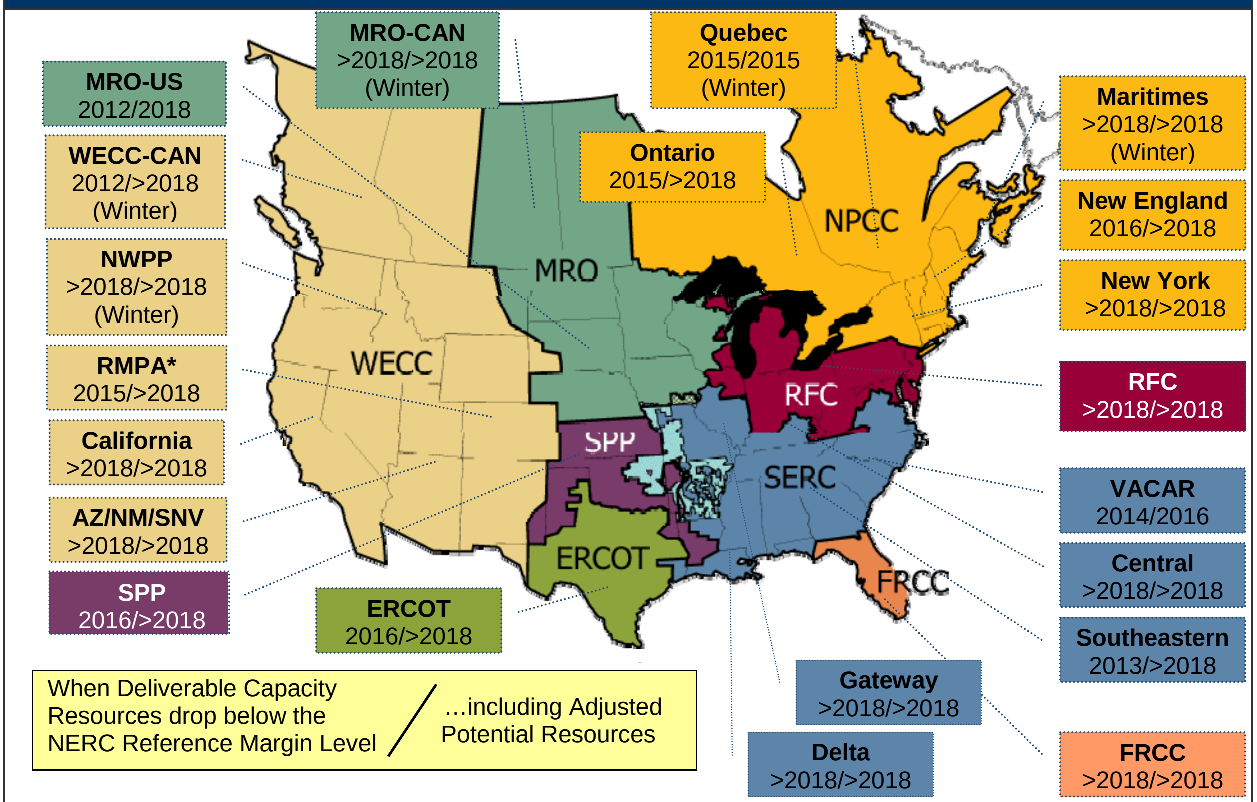
[8] http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf

Summary Reliability Assessment of North America

Estimated Planning Reserve Margins

Reserve Margins[9] in many regions have increased compared to 2008 projections due in large part to the economic recession, which has reduced demand projections. An increase in demand-side management programs and the addition of new resources have also contributed to this trend. Demand is projected to grow within the next three years as the economy recovers. Figure 2 provides the 2009 and 2018 summer Reserve Margins in North America (unless noted as winter) compared to NERC's Reference Margin Level.[10]

Figure 2: Prospective and Adjusted Potential Resources Reserve Margins Compared to NERC's Reference Margin Level



** For more information on the WECC-RMPA subregion, refer to the WECC Highlights section of this report.*

---

[9] "Reserve" margins in this report represent margins calculated for planning purposes (planning Reserve Margins) not operational reserve margins which reflect real-time operating conditions. See *Capacity Margin to Reserve Margin Changes* and *Terms Used in This Report* for more information. See *Estimated Demand, Resources, and Reserve Margins* for specific values.

[10] Each Region/subregion may have its 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 Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.

The SERC-Gateway Reserve Margin for 2009 is projected to be seven percent, which is below the NERC Reference Margin Level of 15 percent due to market factors. However, SERC-Gateway forecasts to have adequate margin level by the following year (2010) continuing through 2018.[11] Deliverable Capacity Reserve Margins in WECC-Canada and MRO-U.S. are projected to be below NERC's Reference Margin in 2012. For more details on Reserve Margins, see the *Estimated Demand, Resources, and Reserve Margins* section of this report.

Drivers:

1. An overall reduction in Net Internal Demand growth.

A two percentage point decrease in projected (summer) Net Internal Demand growth[12] in the U.S. also contributes to higher Reserve Margins over the ten-year period. Demand is projected to increase 15 percent between 2009 and 2018, compared to 17 percent between 2008 to 2017 forecast in last year's report. As shown to the right, this projected growth rate reflects a continued decline from previous forecast periods and parallels a decline in the growth in projected energy use over similar forecast periods.

Table 2: Net Internal Demand and Energy Growth

NERC Long-Term Reliabilty Assessment	Peak Demand Growth (%)	Energy Growth (%)
2005 Report - (2005 to 2014)	19.8	18.2
2006 Report - (2006 to 2015)	19.0	17.2
2007 Report - (2007 to 2016)	17.7	16.9
2008 Report - (2008 to 2017)	16.8	15.7
2009 Report - (2009 to 2018)	14.8	14.5

In Canada, winter peak demand is forecast to increase by over 8,000 MW (from 91,000 MW to 99,000 MW) or nine percent during the next ten years, which is greater than the seven percent growth forecast in last year's assessment (from 92,000 MW to 99,000 MW).

2. Addition of new resources

Supply-side additions have also contributed to improved margins, though substantial uncertainty exists due to the current economic conditions and environmental legislation (see Table 5 and Figure 11 in the *Generation* section). Notably, variable generation sources (wind and solar) increase by more than 249,000 MW over the next decade. Second, gas sources grow by over 106,000 MW to represent the largest source of nameplate capacity (26 percent) and capacity expected on peak (32 percent) by 2018.

---

[11] For more information on these Reserve Margin levels, see the SERC-Gateway *Reliability Assessment Analysiss* section of this report.

[12] The demand growth comparisons here represent Net Internal Demand which is reduced by dispatchable and controllable Demand Response. See *Terms Used in this Report* for a definition of this and related terms. Further, improvements in NERC's data collection of information on demand and Demand Response make more recent figures a more accurate representation of the Net Internal Demand with respect to those resources. However, for the purposes of this rough comparison, the figures presented here are adequate to sufficiently display the declining trend in growth rates across the United States.

3. Increase in Demand-Side Management programs.

As highlighted in the 2008 report, Demand-Side Management continues to reduce overall peak-demand (see *Increased Use of Demand-Side Management Projected to Reduce Peak Demand* section of this report). By 2018, new Energy Efficiency programs are projected to reduce summer peak demand by almost 20,000 MW. Demand Response programs are projected to reduce summer peak demand by over 38,000 MW during the same period.

Planning Reserve Margins Summary:

a. A reduction in demand and an increase in both demand-side management and capacity resources are increasing Reserve Margins.

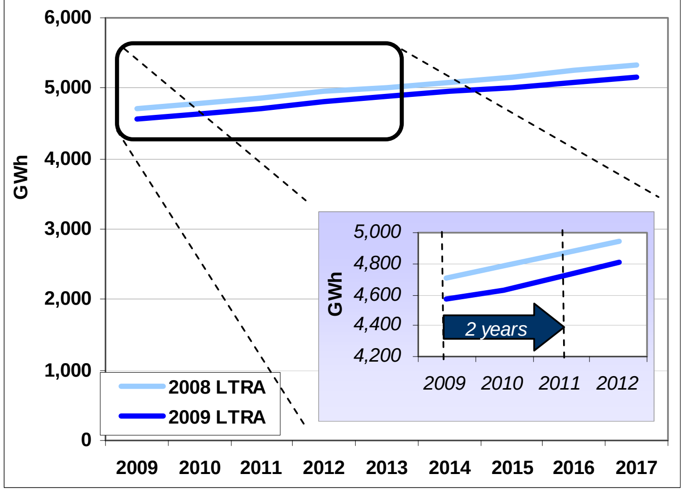
NERC Actions

- Monitor the conditions in SERC-Gateway, WECC-Canada and MRO-U.S. which may require additional resources in the near future.
- Monitor Reserve Margins as the economy recovers which may cause demand to increase rapidly.

Demand

The economic recession[13] is responsible for significant reductions in projected long-term energy use in North America, though its effects on peak demand are realized to a lesser degree. Energy use projections in last year's report for 2009 are now projected for 2011 (See Figure 3).[14] Forecasts indicate that Total Internal Demand will increase in most areas through 2018, but at a slower pace and from a lower starting point. Table 3 displays the slower pace of growth (1.6 percent to 1.5 percent) over the next decade as compared to last year's forecast and illustrates the recovery across the Regions and subregions.

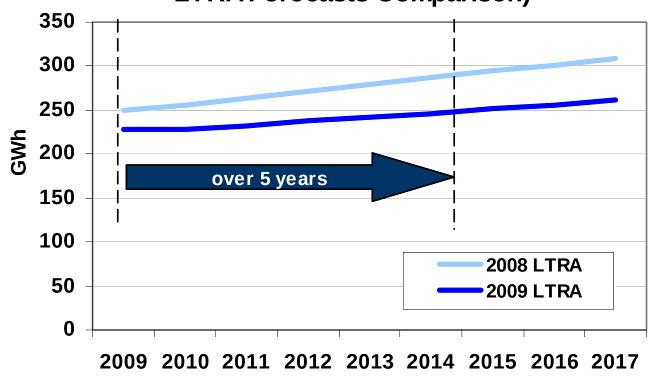
Figure 3: NERC 2009 to 2017 Projected Annual Energy Use (2008 LTRA and 2009 LTRA Forecast Comparison)



The increase in Demand-Side Management contributes to approximately 20 percent of the total reduction in summer peak demand for the 2017 forecast when compared to last year's forecast, while economic recession effects contribute 80 percent.

Many electricity forecasts are based on forecasted economic assumptions and, as noted by NPCC-Ontario, "electricity demand is expected to lag the economic recovery." Regions cite several economy-related drivers for the decrease in forecast electricity demand and use. The reduction in industrial use of electricity appears to be a significant driver noted by several SERC subregions, NPCC, and RFC. However, Regional differences contribute to the complexity of the broad decline, as FRCC indicates a "decrease in peak demand forecast growth rate is attributed to an increase in Demand-Side Management participation as well as higher electricity costs and a decrease in economic development in Florida." Overall, the impact on the FRCC and

Figure 4: FRCC 2009 to 2017 Projected Annual Energy Use (2008 LTRA and 2009 LTRA Forecasts Comparison)



[13] In the U.S., the National Bureau of Economic Research maintains a chronology of the U.S. business cycles and identifies the dates of peaks and troughs that frame economic recession or expansion. http://www.nber.org/cycles/jan08bcdc_memo.html and http://www.nber.org/cycles/dec2008.html An economic recession has also been acknowledged in Canada, see http://www.bankofcanada.ca/en/annual/2008/monpol08.pdf

[14] Figure 3 compares forecast energy use (MWh) from the *2008 Long-Term Reliability Assessment* and the *2009 Long-Term Reliability Assessment* across the common forecast years, 2009 to 2017. Throughout this report, "peak demand" generally refers to demand at peak during a seasonal (winter or summer) period in MW or GW and "use" refers to energy use in MWh, GWh, or TWh.

NPCC Regions are substantial, taking five years to attain the level of energy use projected in last year's report (For example, see Figure 4) for FRCC.

Similar to FRCC, SERC-Gateway's forecast incorporates price elasticity and energy efficiency in its load growth projections. In all five subregions of NPCC, "lowered economic expectations together with aggressive energy efficiency programs have essentially leveled or reduced the anticipated growth in demand for the ten-year study period." For example, NPCC-Ontario has indicated it expects demand to decrease due to the impacts of conservation, embedded generation and industrial restructuring.

Not all regions forecast a long-term decrease in Total Internal Demand growth rates. For example, ERCOT notes "the higher ten-year growth rate (Table 3) in this year's forecast is fueled by the projected strong recovery from the current economic recession reflected in the economic forecast after 2010." MRO-Canada expects an increase in winter peak demand of 0.5 percentage point resulting from "higher residential load growth due to expected population growth and increases in industrial load due to pipeline expansions, mining, and smelting operations."

Demand Projected to Recover at Differing Rates

The NERC *2009 Summer Reliability Assessment*[15] indicated a 1.6 percent drop in forecasted demand across North America when compared to the 2008 report. Comparison of this year's long-term forecasts of peak Total Internal Demand with those recorded in NERC's *2008 Long-Term Reliability Assessment*[16] can provide insights on the expected recovery patterns and permanent impacts of the current economic recession:

- Canada – A two percent drop in (winter) peak demand (Total Internal Demand) compared to last-year's forecast for 2009. Peak demand increases consistently through 2014 then levels off in 2015 with an increased annual growth rate in 2016.

- U.S. – A four percent drop in peak demand compared to last-year's forecast for 2009. In 2011, the U.S. annual growth rates increase then decrease through 2014. Annual growth rates remain the same 2014 through 2018.

- ERCOT – A five percent drop in peak demand compared to last-year's forecast for 2009. Annual growth rates increases through 2012 and then declines.

- FRCC – A five percent drop in peak demand compared to last-year's forecast for 2009. Annual growth rates increase for two years and then remain the same to 2018.

- RFC – A five percent drop in peak demand compared to last-year's forecast for 2009. In 2011 and 2012, the annual growth rates increase and then decline through 2018.

[15] http://www.nerc.com/files/summer2009.pdf
[16] http://www.nerc.com/files/LTRA2008v1_2.pdf

- MRO-US – A five percent drop in peak demand compared to last-year's forecast for 2009. The annual growth rate is above two percent in 2010 and then declines through 2018.

- NPCC-US – A four percent drop in peak demand compared to last-year's forecast for 2009. The annual growth rate increases in 2011 then remains unchanged.

- SERC – A three percent drop in peak demand compared to last-year's forecast for 2009. The annual growth increases in 2011 then declines.

- SPP – Less than one percent drop in peak demand compared to last-year's forecast for 2009. The growth rate declines in 2015 when a number of wholesale load contracts expire.

- WECC-US – A three percent drop in peak demand compared to last-year's forecast for 2009. Annual growth rates appear unchanged after 2014.

Table 3: Total Internal Demand, Projections by Region and Subregion

	2008 LTRA Projected Growth Rate 2008-2017		2009 LTRA Projected Growth Rate 2009-2018	2009 LTRA Annual Growth Rates - Trend Lines 2010 2014 2018
United States				
ERCOT	1.79%	↑	2.13%	
FRCC	2.16%	↓	1.87%	
MRO	2.07%	↓	1.42%	
NPCC	1.07%	↓	0.91%	
New England	1.23%	↓	1.20%	
New York	0.93%	↓	0.66%	
RFC	1.37%	↓	1.35%	
RFC-MISO	1.25%	↓	0.67%	
RFC-PJM	1.44%	↑	1.68%	
SERC	1.89%	↓	1.76%	
Central	1.80%	↓	1.52%	
Delta	1.90%	↓	1.63%	
Gateway	1.02%	↓	0.91%	
Southeastern	2.36%	↓	2.22%	
VACAR	1.81%	↑	1.84%	
SPP	1.56%	↓	1.16%	
WECC	1.84%	↓	1.69%	
AZ-NM-SNV	2.66%	↓	2.31%	
CA-MX US	1.30%	↓	1.28%	
NWPP	1.80%	↓	1.76%	
RMPA	2.33%	↓	1.95%	
Total-U.S.	**1.70%**	↓	**1.57%**	

	2008 LTRA Projected Growth Rate 2008-2017		2009 LTRA Projected Growth Rate 2009-2018	2009 LTRA Annual Growth Rates - Trend Lines 2010 2014 2018
Canada				
MRO	1.24%	↑	1.59%	
NPCC	0.14%	↑	0.40%	
Maritimes	0.77%	↓	0.52%	
Ontario	-1.07%	↓	-1.11%	
Quebec	0.74%	↑	1.23%	
WECC	2.32%	↓	1.97%	
Total-Canada	**0.76%**	↑	**0.88%**	
Mexico				
WECC CA-MX	5.40%	↓	2.49%	
Total-NERC	**1.63%**	↓	**1.50%**	

About this Table:

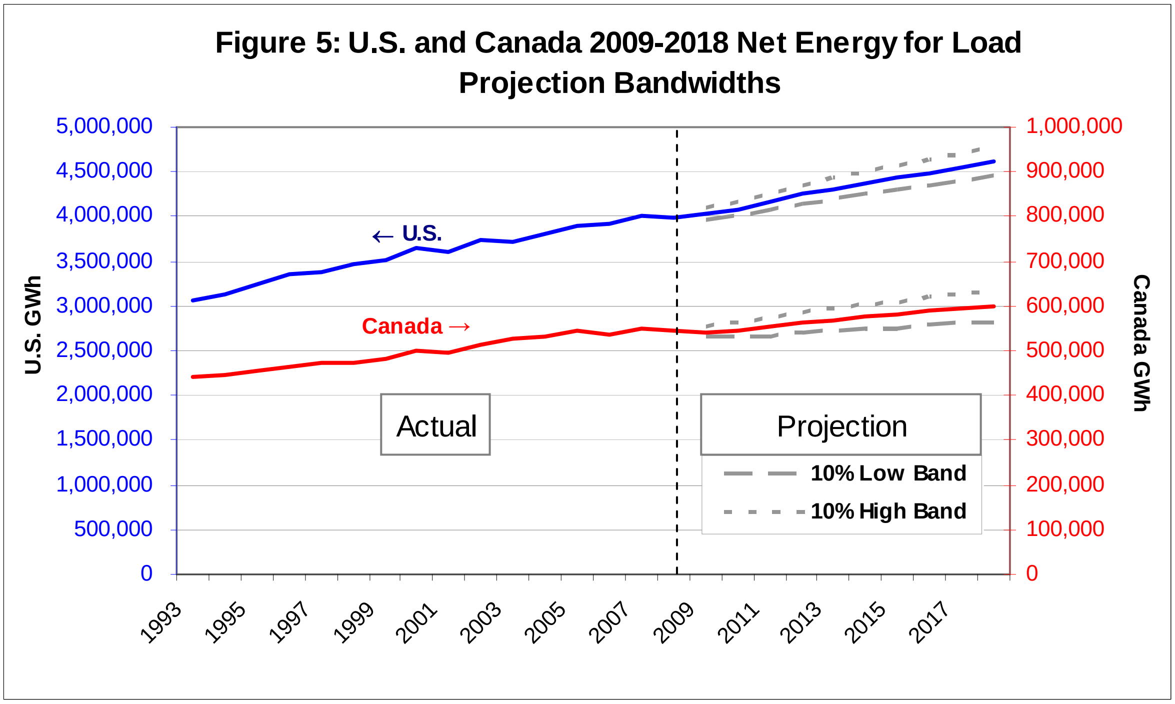
"Projected Growth Rate" - Growth rates calculated using the log-linear least squares growth rate (LLLSGR) method from Regional and subregional Total Internal Demand data collected in 2008 for years 2008 to 2017 and collected in 2009 for years 2009 to 2018. This method of calculation was selected to give proper consideration to all data points in the series and avoid bias due to an exceptionally high or low beginning or ending year. Since many Regions or subregions experience significant increases or decreases in demand in the middle years, this method best reflects the growth over the entire period for this analysis. Elsewhere in this report, Regions and subregions may refer to compound annual growth rate (CAGR) which provides a simple figure for explaining growth between the beginning and ending years. In general, LLLSGR and CAGR provide similar values for a given data set. Note that the 2008 growth rate covers projected rates from 2008 to 2017 and the 2009 growth rate covers projected rates from 2009 to 2018.

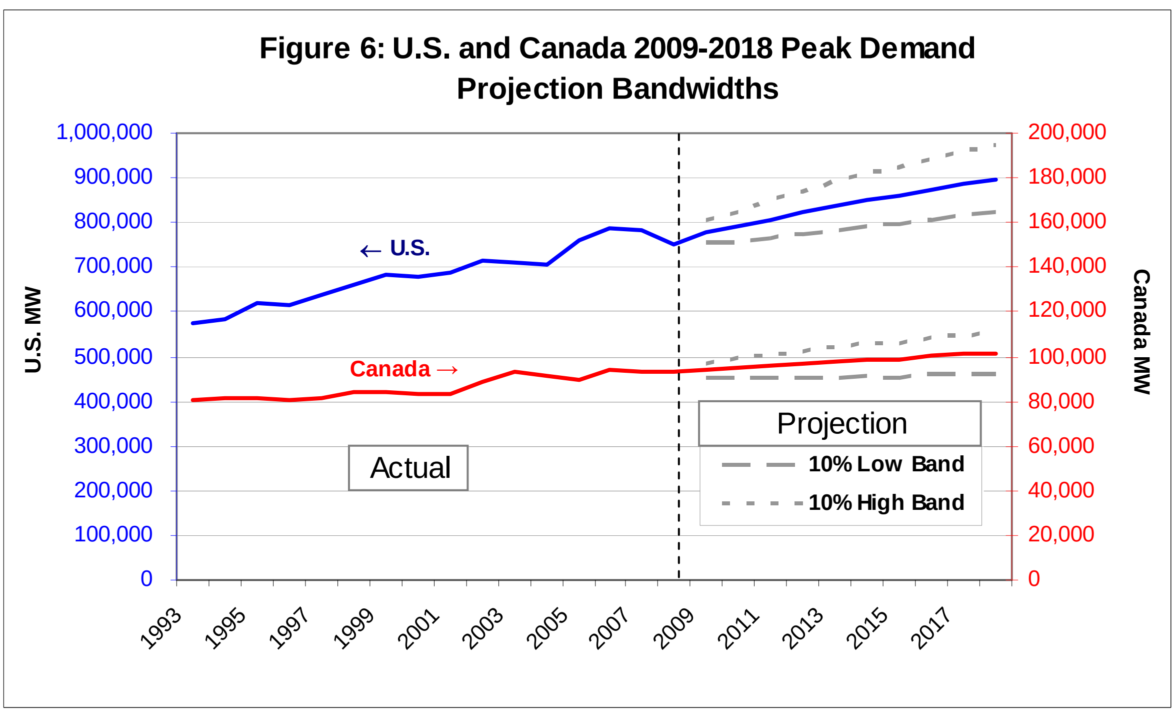
"Annual Growth Rate - Trend Lines" - A line representing the percentage change of Total Internal Demand from one year for Regional and subregional demand data for years 2009 to 2018. It is presented to illustrate the relative differences in demand increases or declines among Regions and subregions over the 2009 to 2018 period. Note that the charts begin at year 2010 to reflect the percentage change from 2009 to 2010.

Note: Total Internal Demand annual growth rate trend lines in Table 3 are based on this year's projections.

Energy and Peak Demand Confidence Bandwidths

U.S. and Canada energy use and peak demand projections appear to increase at trends similar to historical trends from 1993 (Figures 5 and 6).[17]





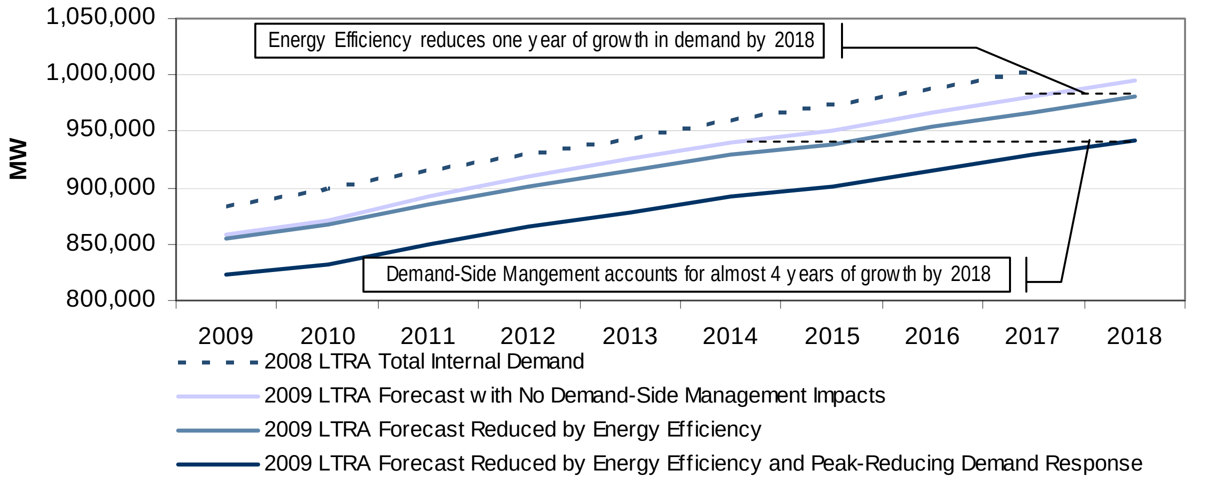
[17] Bandwidths in Figures 5 and 6 were calculated by the NERC Load Forecasting Working Goup. For more detail on these calculations, see the *External Data Validation* section of this report.

Demand-Side Management

To meet resource adequacy requirements in the future, increases in Energy Efficiency and Demand Response, two components of Demand-Side Management (DSM), are projected to reduce peak demand growth and may defer the need for additional generating capacity.[18]

DSM is projected to reduce growth in demand by 4 years by 2018 (see Figure 7) when compared to last year's forecast. When compared to the 2017 forecast, recession effects account for about 25,000 MW of the reduction in peak summer demand while the increase in DSM accounts for 8,000 MW.

Figure 7: Summer Peak Demand Growth Reduced by Demand-Side Management



Energy Efficiency

By 2018, new Energy Efficiency[19] programs are expected to reduce summer peak demand by almost 20,000 MW, accounting for a full year of growth across North America. Much of this peak-demand reduction is contributed from a few subregions, as Energy Efficiency programs are prominent in Ontario subregion and the U.S. portion of the California-Mexico subregion. For example, by 2018, Ontario's summer peak is reduced 2.3 percent attributed to new Energy Efficiency programs.

Generally, Energy Efficiency goals are aimed to reduce energy use (MWh), though peak-capacity reductions are also realized. For example, in New England's Forward Capacity Market, ISO-NE has taken an active approach to audit and monitor the progress of Energy Efficiency resources scheduled to reduce demand during a pre-specified commitment period. In many cases, Energy Efficiency is also embedded in load forecasts and, therefore, not specifically reported.

---

[18] Many federal, state, and provincial policy makers and regulators have identified DSM as a tool to manage peak demand thereby reducing the need for new supply resources.

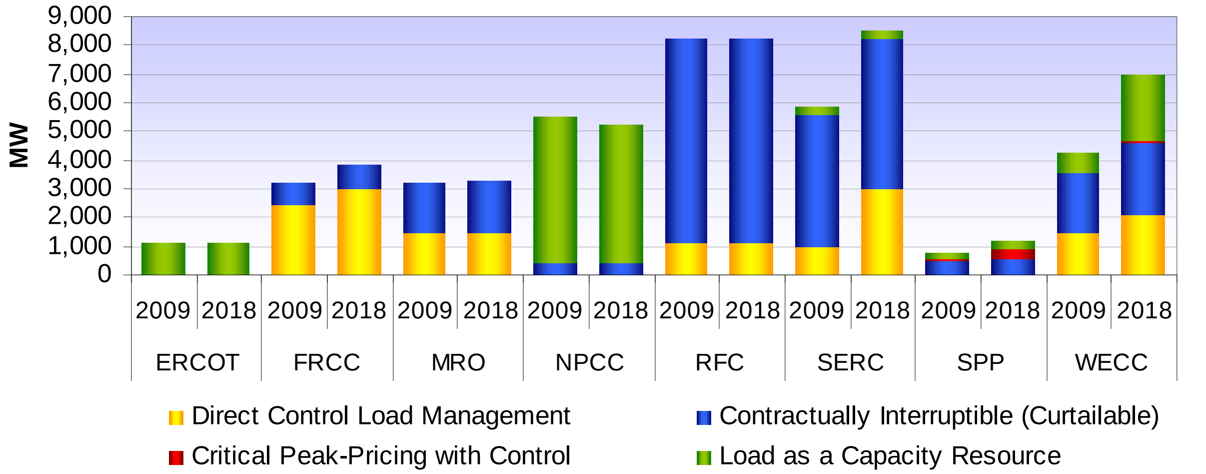
[19] See *Terms Used in This Report* for clarification of "Energy Efficiency."

A potential driver for the expansion of these programs, Renewable Portfolio Standards (RPS) commonly include provisions for Energy Efficiency to account for a portion of the renewable resource requirement, generally no more than 5 percent of energy use (MWh). A multitude of consumer incentive programs will increase Energy Efficiency. The most prevalent are rebate programs for high-efficiency appliances and lighting.

Demand Response

Participation in Demand Response programs continues to grow, not only in magnitude, but also as a percentage of Total Internal Demand through the ten-year timeframe. Over 32,000 MW of Demand Response (both Dispatchable and Controllable) is currently being used to manage peak demand. By 2018, this number is projected to increase to over 38,000 MW (See Figure 8). Significant growth is projected in SERC, SPP, and WECC with increases of 45 percent, 56 percent and 62 percent, respectively.

Figure 8: NERC Summer Peak Capacity Demand Response 2009-2018 Comparison

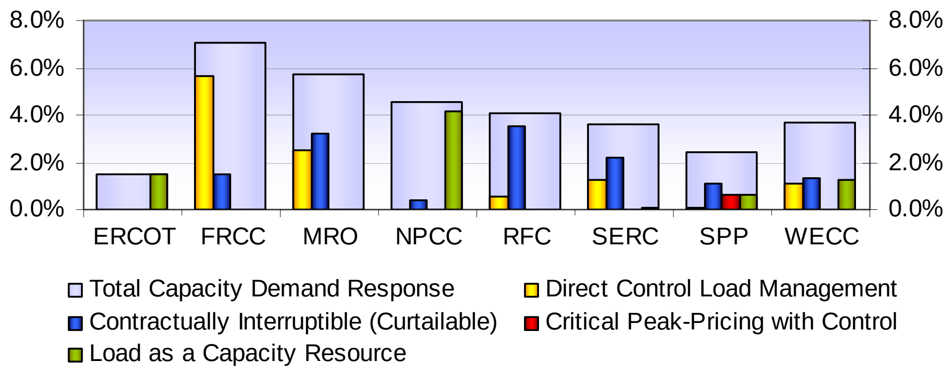


Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of Demand Response resources involve greater forecasting uncertainty. For example, the New England and New York electricity markets integrate large Demand Response programs; however, the long-term availability of these resources remains uncertain. Less understood attributes of the resources, such as response fatigue or economic-base participation rates, must be carefully monitored to assure they do not pose reliability issues in the future. In most cases, forecasting of Demand Response is not performed. Rather, projections are based on resource requirements and the amount contracted during a commitment period.

Demand resources shown in Figure 8 are not limited to being used on peak, but provide reliability benefits during off-peak periods as a flexible resource option for system operators. In fact, in many electricity markets, Demand Response used as a resource is gaining significant penetration in resource portfolios and expected to be dispatched more often to meet firm demand.

In the recent FERC study, *A National Assessment of Demand Response Potential,*[20] the Business-as-Usual scenario aligns with NERC projections for Demand Response in the United States with about 38,000 MW projected by 2018. The Expanded Business-as-Usual case indicates 82,000 MW of Demand Response could be deployed. The Full-Participation case indicates 188,000 MW of Demand Response could potentially be deployed, effectively offsetting ten years of demand growth.[21] Even with the recent economic conditions diminishing peak demand forecasts, Demand Response has continued to become an increasingly important tool for operators to manage demand. Please refer to the *Operational Issues* section for more information.

Figure 9: NERC Projected Demand Response as a % of 2018 Total Summer Peak Demand



Demand Summary:

a. Economic recession drives substantial reduction in demand and energy.
b. Growth is projected to return at varying rates by 2011.
c. Demand-Side Management continues to grow as a resource.

NERC Actions

- NERC, in coordination with the North American Energy Standards Board (NAESB), is developing the Demand response Availability Data System (DADS) to monitor the performance of Demand Response.
- Monitor economic recovery and the resulting impact to demand forecasts.

[20] *A National Assessment of Demand Response Potential*: http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

[21] The Full-Participation Scenario is an estimate of how much cost-effective Demand Response would take place if advanced metering infrastructure were universally deployed and if dynamic pricing were made the default tariff and offered with proven enabling technologies. It assumes that all customers remain on the dynamic pricing tariff and use enabling technologies where it is cost-effective.

Generation

While the addition of large amounts of renewable resources[22] (biomass, geothermal, hydo, solar, and wind) to the system will change the mix of installed, "nameplate" capacity in the coming decade, the mix of supply resources expected to serve peak demand will remain about the same as today. Approximately 260,000 MW of renewable resources are projected[23] to be added to the bulk power system by 2018 as shown in Figure 11. Wind and solar account for 96 percent of renewable resource additions (Table 5) and represent over half of all "installed" resource additions. ERCOT, MRO, RFC, SPP, and WECC all project large wind additions and WECC projects nearly 20,000 MW of solar additions (Table 4).[24] However, the amounts of wind and solar expected on peak are projected to rise only marginally to 38,000 MW and 17,000 MW, respectively. Of the total supply in 2018, fossil-fired, nuclear and hydro, will continue to provide most (over 90 percent) of the capacity necessary to meet peak demand in North America.[25]

The variability and uncertainty associated with wind and solar resources make the addition of this variable generation capacity a significant development requiring planners and operators to change planning processes, forecasting capabilities, operating procedures.[26]

Table 4: Projected Variable Generation Capacity
(Includes Existing, Future, and Conceptual Capacity)

	Wind		Solar	
	2009 (MW)	2018 (MW)	2009 (MW)	2018 (MW)
ERCOT	8,135	46,268	-	225
FRCC	-	-	-	26
MRO	5,924	53,983	-	20
NPCC	1,630	18,015	1	1,153
RFC	1,500	45,700	-	-
SERC	-	-	-	-
SPP	2,257	62,041	-	66
WECC	8,476	30,450	527	19,476
TOTAL	27,922	256,457	528	20,966

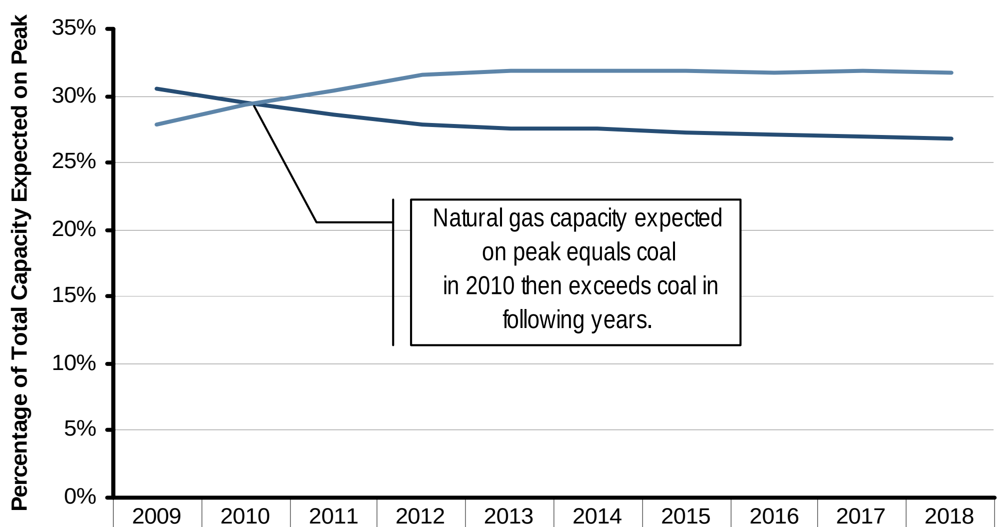
[22] See *Terms Used in This Report* for U.S. Department of Energy, Energy Efficiency & Renewable Energy and government of Canada explanations of "Renewable Energy."
[23] This includes Future and Conceptual capacity resources.
[24] The Conceptual wind and solar capacity projections for WECC reflect the Balancing Authoritys' knowledge of such projects. These projections may be less than publicly available interconnection project queues within the Region.
[25] The "Capacity Expected on Peak" values in Table 5 represent capacity that is planned to be available on peak but may actually be lower due to unexpected or planned (maintenance) outages.
[26] NERC's Special Report: *Accommodating High Levels of Variable Generation* addresses these planning methods, forecasting capabilities, and operating procedures: http://www.nerc.com/files/IVGTF_Report_041609.pdf.

Table 5: Capacity by Fuel Type

	Projected Capacity (Includes Existing, Future, and Conceptual Resources)						Projected Capacity Expected on Peak			
	2009		2018		2009 to 2018 Change		as % of Total		as % of Projected Installed Capacity	
	(MW)	% of total	(MW)	% of total	(MW)	(%)	2009	2018	2009	2018
Resource										
Coal	**307,764**	29.5	**326,837**	22.5	**19,074**	6.2	30.5	26.8	100.0	100.0
Gas	**280,488**	26.9	**387,327**	26.7	**106,839**	38.1	27.8	31.8	100.0	100.0
Hydro	**136,927**	13.1	**144,395**	9.9	**7,469**	5.5	12.5	11.0	92.5	92.8
Nuclear	**113,056**	10.8	**127,907**	8.8	**14,851**	13.1	11.2	10.5	100.0	100.0
Dual Fuel	**111,207**	10.7	**115,022**	7.9	**3,814**	3.4	11.0	9.4	100.0	100.0
Oil	**36,975**	3.5	**39,555**	2.7	**2,580**	7.0	3.7	3.2	100.0	100.0
Wind	**27,922**	2.7	**256,456**	17.6	**228,534**	818.5	0.4	3.1	15.6	14.7
Pumped Storage	**21,071**	2.0	**23,302**	1.6	**2,232**	10.6	2.1	1.9	100.0	100.0
Biomass	**5,406**	0.5	**8,767**	0.6	**3,361**	62.2	0.5	0.7	87.6	91.8
Geothermal	**2,388**	0.2	**2,798**	0.2	**410**	17.2	0.2	0.2	100.0	100.0
Solar	**528**	0.1	**20,966**	1.4	**20,438**	3,870.8	0.0	1.4	77.7	80.5
	1,043,731	100.0%	**1,453,333**	100.0%	**409,602**		100.0%	100.0%		

Projected installed natural gas-fired resources are forecast to increase by over a third or over 106,000 MW by 2018 and represent 32 percent of capacity expected on peak, compared to 28 percent in 2009. Specifically, projections indicate gas will surpass coal as the largest fuel source for generation capacity expected to serve peak demand in 2011 (Figure 10).[27]

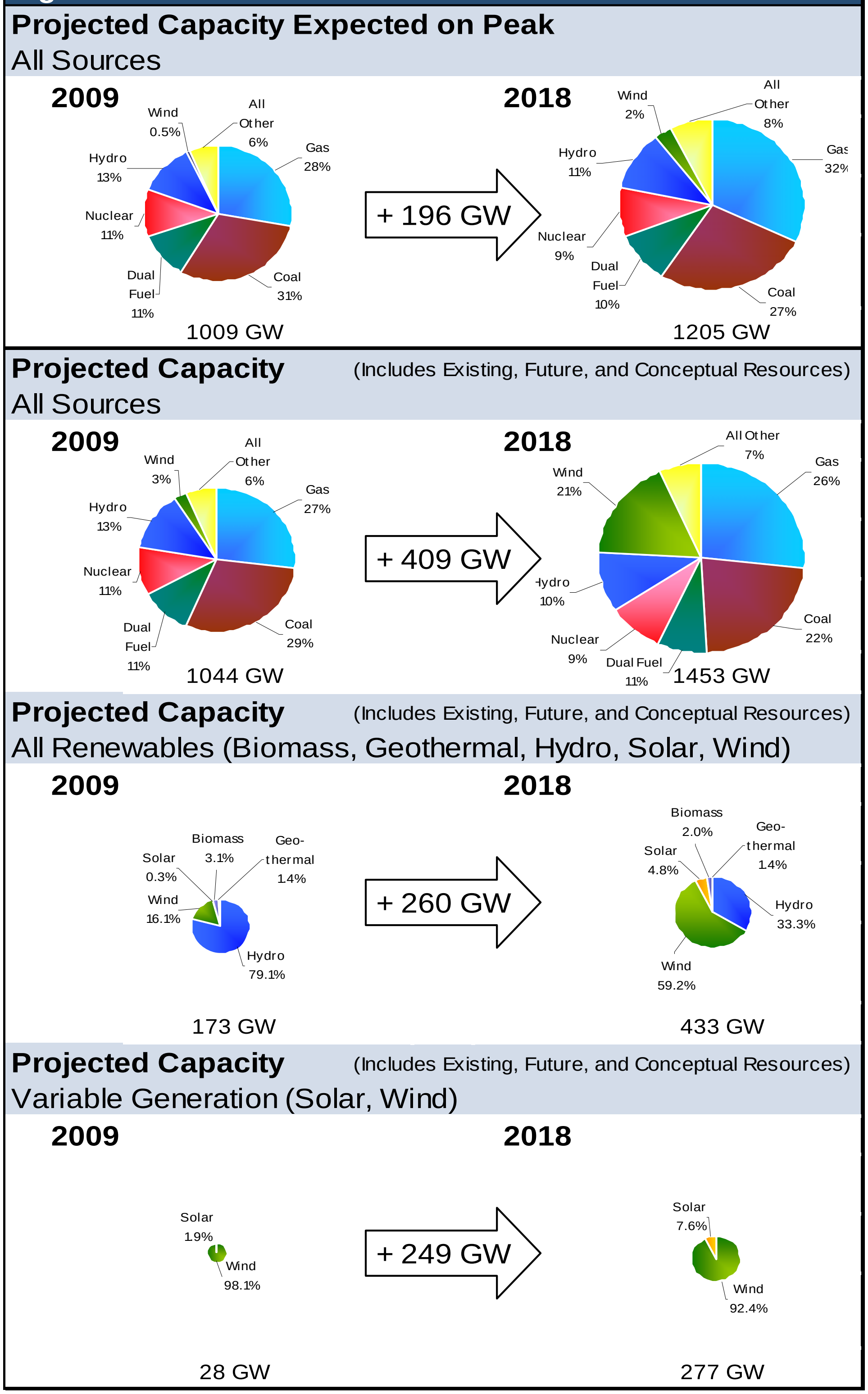
Figure 10: Coal and Gas Capacity Expected on Peak for 2009 to 2018



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal	30.5%	29.4%	28.6%	27.9%	27.5%	27.6%	27.3%	27.1%	27.0%	26.8%
Gas	27.8%	29.3%	30.5%	31.5%	31.9%	31.9%	31.9%	31.7%	31.8%	31.8%

[27] "Dual Fuel" is generation that can use two or more fuels interchangeably. Generally, these generation sources have gas as the primary fuel. The amount of gas used for power generation, both projected installed capacity and capacity expected on-peak, is therefore higher than indicated in the "gas" values above.

Figure 11: 2009 and 2018 Generation Mix



Note: The size of pie graphs presented in Figure 11 (above) are approximately proportional to the capacities on peak that they represent in GW. Percentage values in Figure 11 may differ from Table 5 due to rounding. The "Projected Capacity" is the sum of Existing, Future, and Conceptual Generation Resources—see *Terms Used in This Report* for further explanations of these terms.

Fuel Supply and Reliability: Coal, Natural Gas and Uranium

This section presents a high-level overview of the fuel reliability in North America. It is an independent analysis performed for NERC by *Energy Ventures Analysis, Inc.*[28]

Coal

Historically, coal has been the fossil-fuel with the highest reliability of supply and the most stable price for generating electricity. However, there is reason for the electric power industry to be more concerned in the future about the reliability of coal supply. Short-term disruptions in 2004 and 2008,[29] accompanied by ever-greater price shocks, are a clear indication that the U.S. coal industry no longer has the excess production capacity to respond to surges in demand. Other sectors of the coal supply chain have sought to minimize excess capacity as well, as customers have reduced coal stockpile levels and transportation companies have eliminated excess capacity. Further, productivity in coal production has declined steadily since its peak in 2000, as mining conditions have become more difficult and mining regulations more restrictive.

Natural Gas

A shift to unconventional[30] gas production in North America has the potential to increase reliability of long-term gas supply in the future. However, the precise annual growth rates of gas production from the newer unconventional basins (e.g., shale gas), which are still in their infancy, are uncertain given the large amount of new drilling that is required to extract the gas. Successful development of unconventional gas is dependent on advanced technology that requires horizontal drilling of well bores, hydraulic fracturing of the rock with large amounts of high-pressure water, and real-time seismic feedback to adjust the stimulation method. Issues that may adversely affect future production from unconventional resources include access to, and drilling permits for, land that hold the resources, availability of water, wastewater disposal, and unfavorable state or provincial tax regimes or royalty structures. Accompanying the shift to unconventional basins, recent large-scale expansions of U.S. gas transportation, delivery and storage infrastructure significantly alleviate short-term supply dislocations from potential events such as pipeline outages, production outages or hurricanes.

While market prices are not normally a concern for reliability, their level and volatility drive the pace of overall gas resource development, with sufficient return on capital (e.g., market price) required to stimulate new production. The current low price environment, driven by global economic conditions, poses some concern for gas production, as the number of drilling rigs has decreased by approximately 50 percent from 2008, as the industry attempts to restore equilibrium from an oversupplied condition in 2009. Because the gas industry is focusing on unconventional

---

[28] http://www.evainc.com/

[29] Temporary coal supply shortages occurred in 2004 and 2008. For details see (2004): http://tonto.eia.doe.gov/FTPROOT/features/feature04.pdf and (2008): http://www.eia.doe.gov/cneaf/coal/page/special/article_dc.pdf.

[30] Unconventional gas production is an umbrella term for natural gas that is produced by means that do not meet the criteria for conventional production (natural gas that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore). Unconventional gas includes tight gas, coal bed methane, and shale gas. http://www.eia.doe.gov/glossary/glossary_u.htm

gas wells and U.S. drilling is at a seven-year low, the decline in deliverability from conventional gas wells will accelerate, and this trend may pose a risk if unconventional production is unable to replace it in the long-term.

Uranium: Nuclear Fuel Supply

There is limited capacity in North American nuclear fuel cycle processes given almost 25 years of underinvestment due to the highly sensitive nature of the technologies, the large capital costs, the large-scale of the required industrial operations, and safety concerns. Enrichment is perhaps the most constrained aspect of the fuel cycle; however, impacts due to the reliability of the nuclear fuel supply have not yet emerged in North America. North American dependence on imported supplies of enriched uranium may leave it vulnerable to long-term supply disruptions, particularly as global demand for enriched uranium accelerates with the construction of new plants outside of North America.

Generation Summary:

a. Natural gas exceeds coal as the primary fuel for on-peak capacity in 2011.
b. 260,000 MW of "nameplate" wind and solar generation are projected to be added to the system through 2018.

NERC Actions

- As gas becomes a larger proportion of the fuel used to power generation, continue to assess the natural gas supply and delivery and their impacts to bulk power system reliability.
- With the increase of variable generation in the system, continue efforts of NERC groups to investigate planning and operating tools and analysis methods.

Transmission

The ability to site and build transmission is emerging as one of the highest risks facing the electric industry over the next ten years.[31] A 15 percent increase in the miles of transmission is projected by 2018 in North America. With the increase in wind and solar resource projections, transmission will be needed to "unlock" renewable resources in remote areas, increase diversity of supply, and provide access to ancillary services required to manage their variability.

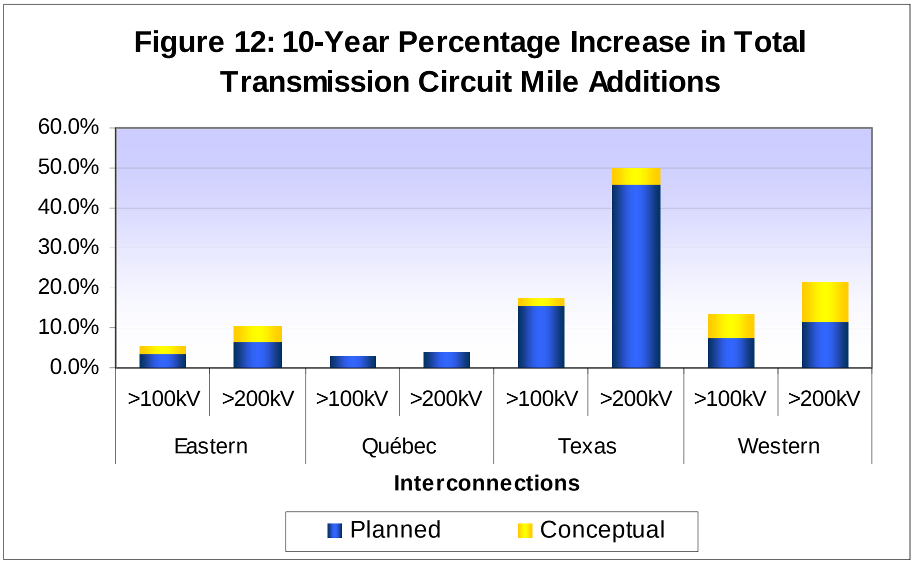
Table 6: Transmission Plans by Circuit Mile Additions > 100 kV

		2008 Existing	Under Construction	2009-2013 Planned Additions	2009-2013 Conceptual Additions	2014-2018 Planned Additions	2014-2018 Conceptual Additions	Total by 2018
United States								
ERCOT	-	28,665	-	4,375	137	100	358	33,635
FRCC	-	7,319	143	72	70	197	-	7,801
MRO	-	36,482	618	682	829	597	1,198	40,406
NPCC	-	13,638	53	373	6	17	16	14,103
NPCC	New England	2,770	53	352	-	17	16	3,208
NPCC	New York	10,868	-	21	6	-	-	10,895
RFC	-	60,074	63	1,246	-	87	-	61,470
SERC	-	97,256	711	1,132	495	331	1,279	101,204
	Central	18,114	222	96	9	-	13	18,454
	Delta	16,431	148	202	-	47	-	16,828
	Gateway	7,751	19	48	56	-	285	8,158
	Southeastern	27,234	277	175	278	156	628	28,748
	VACAR	27,726	64	660	208	128	638	29,424
SPP	-	23,593	205	900	123	114	189	25,123
WECC	-	98,030	3,016	3,283	1,679	1,203	5,521	112,732
	AZ-NM-SNV	15,562	1	659	72	754	1,577	18,625
	CA-MX US	27,004	273	956	765	160	2,508	31,665
	NWPP	43,255	2,415	852	842	152	1,436	48,952
	RMPA	12,209	327	817	-	137	-	13,490
Total-U.S.		365,058	4,809	12,063	3,338	2,645	8,562	396,474
Canada								
MRO	-	12,188	-	121	155	1,220	161	13,845
NPCC	-	45,300	376	428	290	361	831	47,586
	Maritimes	4,992	51	27	-	-	103	5,173
	Ontario	17,624	182	218	290	-	728	19,042
	Quebec	22,685	143	183	-	361	-	23,372
WECC	-	21,189	-	801	-	153	-	22,143
Total-Canada		78,677	376	1,350	445	1,734	992	83,574
Mexico								
WECC	CA-MX Mex	1,313	-	284	-	-	52	1,649
Total-NERC		445,048	5,185	13,696	3,783	4,379	9,606	481,697
Eastern Interconnection		273,166	2,026	4,771	1,967	2,562	3,674	288,167
Quebec Interconnection		22,685	143	183	-	361	-	23,372
Texas Interconnection		28,665	-	4,375	137	100	358	33,635
Western Interconnection		120,532	3,016	4,368	1,679	1,356	5,573	136,524

[31] Transmission siting was ranked as a high-risk issue based on the 2009 Planning Committee Risk Assessment. For more information refer to the *Emerging Issues* section.

A notable action item identified in the *2008 Long-Term Reliability Assessment* was to collect more information on existing and projected transmission (Table 6). Greater visibility on the status of transmission projects[32] and identification of the primary reasons individual transmission lines are needed enables NERC to assess what is driving their development and provides granularity, which differentiates the stages of development. Additionally, the threshold for transmission data was reduced to voltages 100 kV or greater.

Since 2008, more than 2,800 miles of transmission greater than 200 kV has been built, with an additional 4,600 miles currently under construction.[33] Significant transmission additions, to existing transmission facilities, are projected in some areas (Figure 12). In the Texas Interconnection, high-voltage transmission is expected to increase by almost 50 percent over the ten-year period to accommodate new wind generation.



Selected Interconnection Highlights:

- By 2018, the **Western Interconnection** is projected to add up to 21 percent more high-voltage transmission. WECC's Regional transmission planning group, the Transmission Expansion Planning Policy Committee (TEPPC), has taken steps to identify where transmission should be constructed to unlock renewable generation. Renewable energy projects and reinforcements to the existing transmission system are both identified in WECC's ten-year plans. TEPPC also identified more transmission is needed to take advantage of the diversity found in variable generation and Demand-Side Management over WECC's large geographic area. In addition, transmission developments are also expected to help reduce future North-South transmission constraints.

[32] In 2009, NERC changed its data collection threshold on bulk power transmission from *greater than 200 kV* to *greater than 100 kV*. 2009 data includes all bulk power transmission greater than 100 kV. 100 to 199 kV transmission is not included when comparing prior year data.

[33] See Terms Used in This Report for more details on Transmission Status Categories.

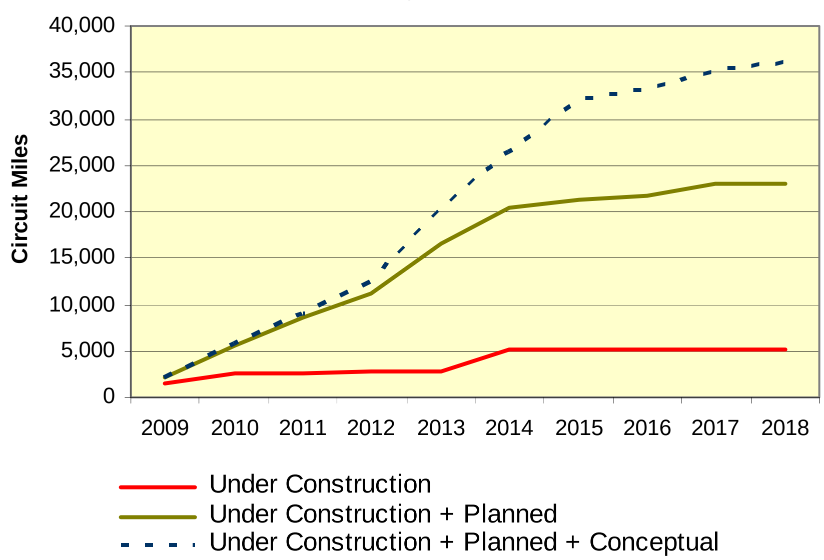
- Within the **Texas Interconnection**, the Competitive Renewable Energy Zones (CREZ) transmission plan specifically supports the integration of variable generation and is expected to be completed by 2013. Over 1,800 miles of 345 kV will be added as part of this expansion plan.

Transmission Status Categories – Transmission additions were categorized using the following criteria:

- **Under Construction**
    - Construction of the line has begun
- **Planned** (any of the following)
    - Permits have been approved to proceed
    - Design is complete
    - Needed in order to meet a regulatory requirement
- **Conceptual** (any of the following)
    - A line projected in the transmission plan
    - A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as "Under Construction" or "Planned"
    - Projected transmission lines that are not "Under Construction" or "Planned"

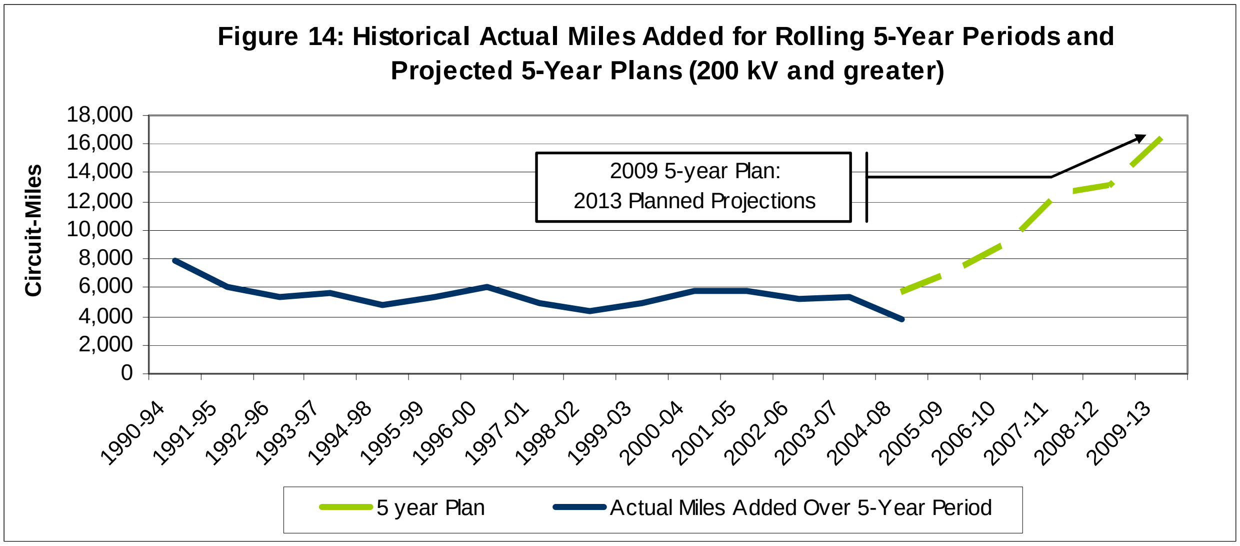
Of the over 36,000 miles of projected transmission over the next ten years, 28,000 miles are either Planned or currently Under Construction. Figure 13 shows total projected Transmission Line Additions greater than 100 kV. Circuit-Miles are accumulated each year by Transmission Status, as defined in the box above. Because future requirements may change, not all of these lines may be built.

Figure 13: Transmission Line Additions > 100kV - Circuit Miles by Transmission Status

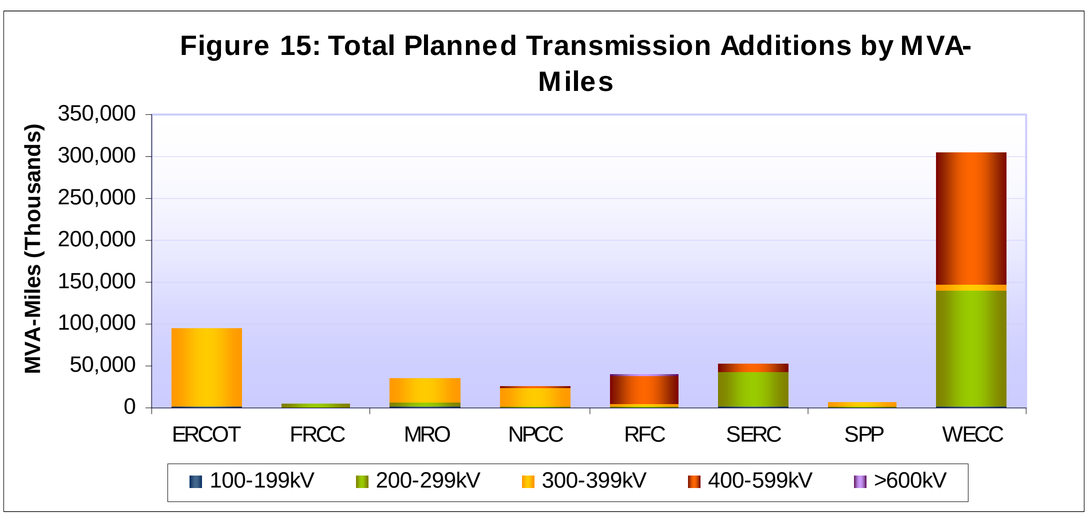


The lines in this Figure represent a cumulative value for each year.

An analysis of the past 14 years shows that the siting and construction of transmission lines will need to significantly accelerate to maintain reliability over the coming ten years. Through the period of this analysis, actual miles constructed over five-year periods have roughly averaged 6,000 Circuit-Miles, Figure 14 (blue line).[34] Recent five-year plans indicate an increasing amount of transmission will be needed, significantly exceeding this average. For example, the actual miles projected to be constructed over the five-year period from 2009 to 2013 is approximately 16,000 Circuit-Miles. For more information on this topic, refer to the *Emerging Issues: Transmission Siting* section.

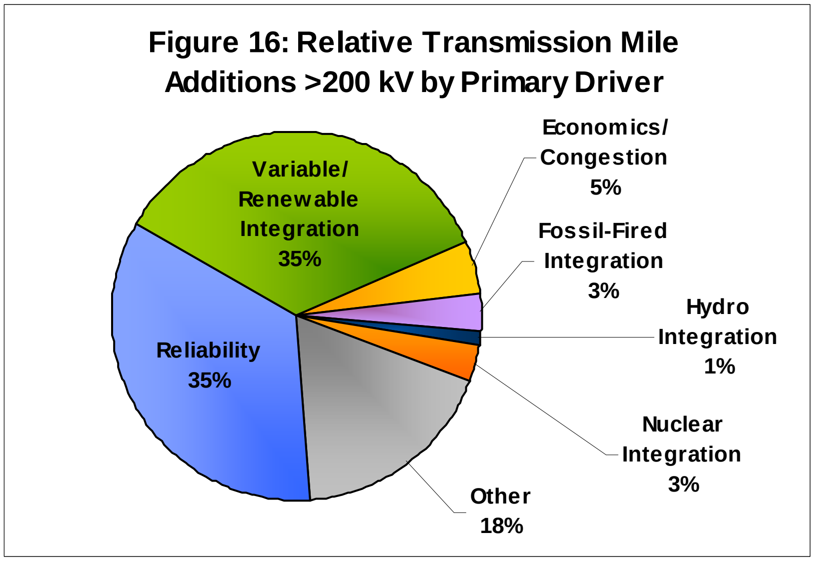


Projected transmission capacity additions provide another measure of transmission additions. Figure 15 includes projected MVA-Miles developed by weighting the transmission capacity ratings by the number of miles. While this may not fully represent increased reliability provided by individual lines where the benefits are many times independent of length, it does provide insights into regional efforts to increase the capacity of the bulk power transmission system.



[34] For example, approximately 4,000 Circuit-Miles were constructed over the five-year period from 2004 to 2008.

Along with the increased granularity on the status of transmission plans, NERC gathered information on key drivers of individual transmission line and infrastructure development projects. Bulk power system reliability and the integration of variable generation emerged as the predominant reason for projected transmission additions and upgrades (Figure 16) over the next ten years. Of the total miles of Under Construction, Planned, and Conceptual transmission greater than 200 kV, 35 percent (11,000 miles) is needed for reliability. An additional 11,000 miles will be needed to integrate of variable and renewable generation.



Transmission Summary:

a. While progress has been made in the development of transmission, much work will be required to ensure that Planned and Conceptual transmission is sited and built.
b. Significant transmission will be required to "unlock" projected renewable resources. Without this transmission, the integration of variable resources could be limited.

NERC Actions

- Continue to collect and report detailed transmission data and conduct special reliability assessments as trends unfold.
- Collect information on transmission project delays and related causes.

Operational Issues

Environmental Restrictions

Regions reported that environmental restrictions and existing regulations will not impact reliability through 2018. The environmental restrictions identified included water discharge temperature and fossil-fueled generator emissions. Some Regions reported that unfavorable weather conditions and the resultant operating restrictions could result in capacity reductions. However, due to the relatively small contributions of facilities at risk for such capacity reductions, the reductions are not expected to impact reliability. For example, ERCOT, FRCC, and the NPCC subregions of Maritimes, Ontario, and Québec reported no major environmental or regulatory restrictions havin a significant impact on reliable operations are expected over the ten-year assessment period.

Two highlighted examples provided by the NERC Regions include:

- ISO New England reports that hot days and low hydrological conditions could present the conditions where river-based generating units are subject to reduced capacity to ensure water discharge temperatures are within environmental limits.
- The New York Independent System Operator reports that the New York Department of Environmental Conservation is developing several proposals to lower emission limitations from generators in New York State. If such limitations are implemented without sufficient flexibility, up to 3,125 MW of capacity may no longer be available to meet peak load conditions and this may affect the resource adequacy criterion for all years from 2009 through 2018.

The uncertainty resulting from environmental regulations and restrictions can delay needed investments to support bulk power system reliability. For example, the impact of greenhouse gas reduction legislation is addressed in the *Emerging and Standing Reliability Issues* section of this report within the *Greenhouse Gas Legislation Standing Issue*.

Variable Generation and Operational Challenges

The continued development of large-scale variable generation, predominately wind, can increase operational challenges. A rapid increase or decrease of wind generation, often referred to as "ramping," can have a significant impact on the power flowing through the bulk power system as noted by MRO for the Wisconsin-Upper Michigan System's (WUMS) western and southern interfaces. Generally, however, Regions such as SPP note that the operational impacts of wind generation on regulation and control performance of the bulk power system are still not fully understood. Many wind integration studies in the U.S. have provided information about the impact of wind on the bulk power system. Further study and industry experience will be required to mitigate operational concerns and support large-scale integration of variable generation. In addition, SPP indicated the need for data collection and situational awareness must occur at a more granular level to be useful, particularly when the information is intended to assess regulation and spinning reserve needs.

To address operational issues, NERC[35] and the Regions have begun several initiatives to facilitate the reliable integration of variable generation.[36] These coordinated initiatives include focused work groups, integration studies, equipment and system modifications, and increased forecasting efforts. Some examples include:

- NERC's Integration of Variable Generation Task Force issued a report in April outlining reliability considerations for the integration of large-scale variable generation. The group continues to execute its work plan, as outlined in the report.[37]
- Working groups and task forces have been developed to review potential challenges and examples, include ERCOT's Renewable Technologies Working Group and SPP's Wind Integration Task Force.
- Many Regions and subregions are initiating wind integration studies. These include ISO New England's New England Wind Integration Study and the Eastern Wind Integration and Transmission Study[38] (EWITS), both of which contribute to multi-Region efforts such as the Joint Coordinated System Plan. WECC is also collaborating with NREL in the development of the Western Wind and Solar Integration Study.
- At the equipment and system level, the Los Angeles Department of Water and Power (LADWP) in WECC has begun refurbishing existing pumped-storage units to integrate their operations with variable wind energy output. In addition, LADWP has commenced repowering existing steam units with gas turbine units to provide quick start, low minimum load and high ramp rate operations with frequent cycling ability to match variable generation characteristics.
- Another example at the equipment and system level includes ERCOT's implementation of voltage ride-through requirements for new wind generation—ERCOT is studying the benefits of the application of these requirements to existing wind generation.[39] Recognizing the benefits of large area collaboration, the Maritimes subregion plans for the individual jurisdictions to coordinate the sharing of wind data and possibly wind forecasting information and services.

Further, a host of forecasting efforts are underway across NERC to better anticipate wind generation and improve operations—*Please refer to the Variable Generation Forecasting Improvements and Programs section of this report for more information on forecasting.*

Additional review of the planning and operational reliability impacts related to variable generation, including future concerns, are addressed in the *Emerging and Standing Reliability Issues* section of this report within the *Greenhouse Gas Legislation Standing Issue*. Furthermore, the 2009 *NERC Long-Term Scenario Assessment* will provide insights on the impacts of significant changes, including large increases of wind resources in some Regions.

---

35 NERC's Integration of Variable Generation Task Force is reviewing these issues. http://www.nerc.com/filez/ivgtf.html

36 http://www.nerc.com/files/IVGTF_Report_041609.pdfhttp://www.nerc.com/filez/ivgtf.html

37 http://www.nerc.com/files/IVGTF_Report_041609.pdf

38 http://wind.nrel.gov/public/EWITS/AWST_EWITS_Final_Technical_Report_Draft.pdf and http://mercator.nrel.gov/wwsi/

39 FERC Order 661 states requirements for voltage-ride through capabilities http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10594521

Variable Generation Forecasting

Throughout the continent, Regions report varying levels of action concerning forecasting of variable generation output:

- Regions with established wind resources, such as ERCOT, use a centralized wind forecasting system.
- In NPCC, wind projects are required to transmit atmospheric data (wind speed, wind direction, temperature) to the local System Operator for wind forecasting needs. Subregions like Maritimes plan to coordinate the sharing of wind data and possibly wind forecasting information and services.
- WECC recognizes that an increase in variable resources places an increased demand on the traditional resources used to balance systems. This may drive WECC Balancing Areas to purchase improved wind forecasting programs, assess the need for increased spinning reserves, and develop other methods to manage system reliability impacts.

Improved forecasting and data collection can lead to improved models and processes. ISO-NE, ERCOT, and PJM provide examples:

- ISO-NE's Wind Integration Study focuses on what is needed to effectively plan for and integrate wind resources into system and market operations.
- 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 risk mitigation.
- PJM began utilizing a centralized Wind Power Forecast within operations on 4/1/2009. PJM is actively integrating the Wind Power Forecast within PJM market/operational manuals, procedures and toolsets.

Demand Response and Operational Flexibility

As mentioned previously, Demand Response not only provides a way to manage peak demand, but increase operational flexibility by providing ancillary services and contributing to operating reserve portfolios. The use of Demand Response for Ancillary Services is constant since last year and will remain so throughout the ten-year period.[40] In ERCOT, Demand Response provides the greatest amount of contingency reserve for a single Balancing Authority, as shown in Figure 17.

With legislation and regulation supporting the construction of renewable resources which are variable in nature (e.g., wind and solar), Demand Response resources may increase to provide ancillary services.

For Demand Response to be a viable option for capacity and reliability planning, operators will require the same certainty as traditional generation. Direct Control Demand Response has the potential to act as spinning reserves, providing push-of-a-button dispatch. Non-Spinning Reserves have a less stringent performance criterion, permitting other varieties of Demand Response to participate. In some Regions Energy-Voluntary Demand Response can be also be

[40] For more information on Demand Response Categorization, refer to the *Reliability Concepts Used in this Report* section.

used by system operators in emergency situations. Though voluntary, requests through public appeals or certain program offerings can offer an expected capacity reduction value which operators can implement during capacity constraints.

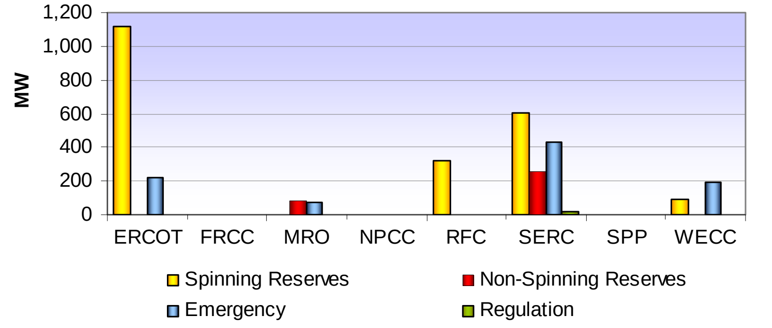


Figure 17: Ancillary Services and Energy-Voluntary Demand Response

Frequency Response

Frequency Response, the ability to maintain load-generation balance within acceptable limits, can be used to measure real power balancing control performance. It is a fundamental reliability component provided by a combination of governor and load response. Frequency Response represents the actual MW contribution to stabilize frequency following a disturbance. Prolonged system recovery from a disturbance or normal operating frequency excursions (either high or low) could indicate the need for new methods of system management.

In order to better understand this emerging concern and maintain an acceptable level of frequency response, NERC should begin collecting frequency response data on behalf of its stakeholders to enable proper modeling and identify causes of its apparent decline.[41] Industry can then set plans in place to support appropriate action in planning, design and operation of the bulk power system. Efforts on this subject will be coordinated under NERC's Frequency Initiative.

Operational Issues Summary:

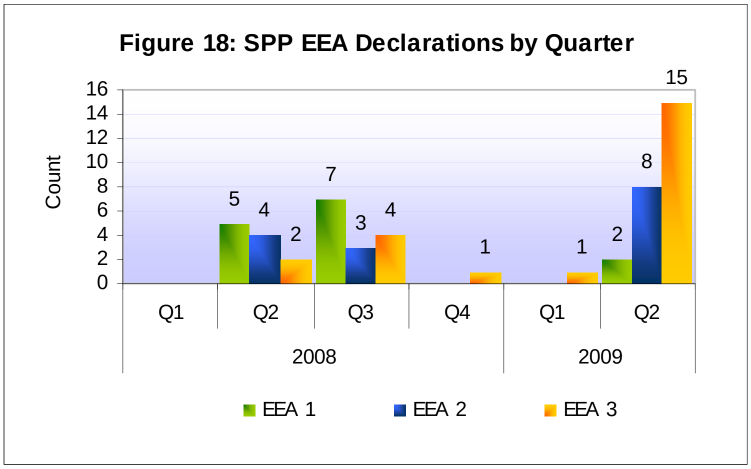
a. Variable generation can cause operational challenges.
b. NERC and Industry have a coordinated approach to study frequency performance decline.

NERC Actions

- A post-seasonal operational reliability assessment initiative will be implemented by NERC and the Regions to provide more a more in-depth assessment at the operational level (types of resources, operating or contingency reserves, etc.).
- Collect data on frequency response to enable accurate modeling and support root cause analysis.

[41] http://www.nerc.com/docs/standards/sar/SAR_Frequency_Response_Final_Draft3_30Jun07.pdf

Level 3 Energy Emergency Alerts Increase in SPP



Capacity and Energy Emergency Alerts (EEAs) are called by system operators when demand exceeds available supply on the system. The total number of capacity and energy emergency events in NERC's Reliability Coordinator Information System (RCIS) database are grouped into three categories EEA 1, EEA 2 and EEA 3 based on Standard EOP-002 (Capacity and Energy Emergencies).[42] EEA 1 and EEA 2 are, in effect, operating procedures used to avoid the interruption of firm customer load as defined in EEA 3. Analysis identified transmission constraints, extreme weather, significant short-term load forecast errors and unplanned generation outages are the main causes of these emergency events.

EEA 2 and EEA 3 rose significantly in SPP during the second quarter of 2009, with eight EEA 2 and fifteen EEA 3 declarations, as shown in Figure 18. This increase is driven, in large part, by the demand in the Acadiana Load Pocket,[43] where SPP anticipates that the ability to adequately meeting firm demand will be a concern.

As outlined in SPP's Regional self-assessment, since June 2009, SPP has been working with each entity to resolve the issues and put in place long-term solutions. The SPP Independent Coordinator of Transmission facilitated an agreement with members in the Acadiana pocket to expand and upgrade electric transmission in the area[44]. The joint project includes upgrades to certain existing electric facilities as well as the construction of new substations, transmission lines, and capacitor banks, and the total estimated cost is approximately $200 million.[45] Each utility is responsible for various components of the project work. All upgrades are expected between 2010 and 2012. The detailed expansion and upgrades are available on the SPP website.[46] When completed, these upgrades will address the resource and transmission adequacy issues currently experienced in the Acadiana area.

Energy Emergency Alerts NERC Actions:

- Continue to monitor Level 3 Energy Emergency Alerts
- Request information from Regions on industry actions taken to mitigate EEA 3 trends. Report the findings in future Assessments.

---

[42] See http://www.nerc.com/files/EOP-002-2_1.pdf for more Capacity and Energy Emergency Event definitions.
[43] Refer to SPP's Regional Assessment for more details of adequacy issues in the Acadiana Load Pocket.
[44] In this case, additional transmission was determined to be the solution to alleviate transmission constraints; however, additional local generation or demand-side management may alleviate constraints in some cases.
[45] http://oasis.e-terrasolutions.com/documents/EES/ICT%20Acadiana%20Load%20Pocket%20Study%20Report_updated.pdf
[46] http://www.spp.org/publications/SPP_Acadiana_news_release_1-19-09.pdf

Adequate–Level-of-Reliability (ALR) Metrics

Introduction

Carefully selected and vetted metrics have the potential for indicating impending reliability issues and performance. Seven metrics are included in this year's discussion. They are:

ALR 1-3	Planning Reserve Margin
ALR 1-4	BPS Transmission Related Events Resulting in Loss of Load
ALR 2-4	Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events
ALR 2-5	Disturbance Control Events Greater than Most Severe Single Contingency (MSSC)
ALR 4-1	Percent of Automatic Transmission Outages caused by Failed Protection System Equipment
ALR 6-2	Energy Emergency Alert 3 (EEA3)
ALR 6-3	Energy Emergency Alert 2 (EEA2)

NERC is reviewing these and other data to provide the appropriate reliability performance trends to monitor. No conclusions as to the absolute value of any of these metrics can be drawn at this time. While the metrics may show trends or variances from year-to-year, no determination has been made as to what indicates an "acceptable" level of performance. Rather, they show the performance from year-to-year and can be a basis for further root-cause analysis.

Further, the metrics should not be compared between Regions or subregions as their BPS characteristics and market structures differ significantly in terms of number of facilities, miles of line, system expansion design approaches, and simple physical, geographic, and climatic conditions.

The initial set of metrics presented in this report have been vetted by the industry via the Reliability Metrics Working Group (RMWG)[47] along with the Planning and Operating Committees.

[47] Through the creation of the RMWG the PC and OC have promoted the development of performance metrics for the North American Bulk-Power System (BPS). (BPS is a defined term under Federal Power Act Section 215.) The intent of this metrics program is to fulfill the obligations of the ERO relative to benchmarking by providing a slate of agreed upon metrics, which can yield an overall assessment of reliability of the BPS. The RMWG's charge is to do so within the context of the "Adequate Level of Reliability" (ALR) framework as set out in a December 2007 report Definition of "Adequate Level of Reliability" (http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf) and filed with the FERC for "information" in response to a FERC directive. In a letter to the FERC dated May 5, 2008

The RMWG expects with publication of this data, issues may be identified which require review and modification of the reported data. The list of metrics will change over time. In some cases, the database for a given metric does not yet contain enough historical information to reveal useful information. The selections here and in the future will be based on the ranking process, which recognizes a metric's potential for indicating impending reliability issues and performance.

It is important to note that this activity is only in its early stage. Identifying benchmarks for performance is a separate and future activity which may aid the industry in quantifying its reliability performance.

These metrics are discussed in detail below.

ALR 1-3. Planning Reserve Margin

Background

Planning Reserve Margin[48] is designed to measure the amount of generation capacity available to meet expected demand in the planning horizon.[49] Coupled with probabilistic analysis, calculated planning Reserve Margins have been an industry standard used by planners for decades as a relative indication of adequacy.

Generally, the projected demand is based on a 50/50 forecast.[50] Planning Reserve Margin is the difference between available capacity and peak demand, normalized by peak demand and shown as a percentage. Based on experience, for portions of the bulk power system that are not energy-constrained, Planning Reserve Margin indicates the amount of capacity needed to maintain reliable operation while meeting unforeseen increases in demand (e.g., extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, Planning Reserve Margin trends identify whether capacity additions are projected to keep pace with demand growth.

Limitations

As the Planning Reserve Margin is a capacity based metric, it does not provide an accurate assessment of performance in energy-limited systems, e.g., hydro capacity with limited water resources.

(http://www.nerc.com/files/Adequate_Level_of_Reliability_Defintion_05052008.pdf.) NERC fulfilled its obligation in this regard. The RMWG has developed and implemented a decision-making process and has begun to apply it to the myriad field of possible metrics in order to provide a single source for the decisional process. The RMWG is carrying out the duties outlined in its scope using the principles espoused in the creation of the ERO; namely the application of industry expertise and use of technical judgment.

[48] Planning Reserve Margin equals the difference in Deliverable or Prospective Resources and Net Internal Demand, divided by Net Internal Demand. Deliverable Resources are calculated by the sum of Existing, Certain and Future, Planned Capacity Resources plus Net Firm Transactions. Prospective Resources include Deliverable Resources and Existing, Other Resources. Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load (DCLM, IL, CPP w/control, LaaR).

[49] Note: The Planning Reserve Margin indicated here is not the same as an operating reserve margin that system operaters use for near-term operations decisions.

[50] These demand forecasts are based on "50/50" or median weather (a 50% chance of the weather being warmer and a 50% chance of the weather being cooler).

As the Planning Reserve Margin is a capacity based metric, it does not provide an accurate assessment of performance for energy-limited systems highly dependent on hydro capacity with limited water resources.

Data used here is the same data submitted to NERC for reliability assessments for seasonal and ten-year long-term reliability assessments.

Assessment
Planning Reserve Margins in United States and Canada appear to increase from 2009 to 2012 then decrease through 2018 (Figures Metrics 1 and 2). Planning Reserve Margins in Canada decline to 9 percent in 2018 and fall below the NERC Reference Reserve Margin Level of 10 percent.[51]

Figure Metrics 1

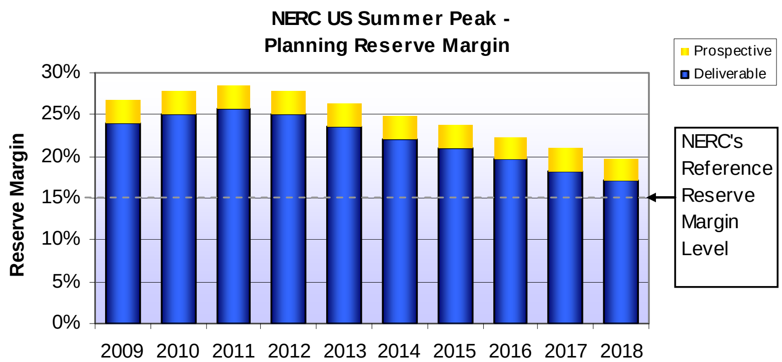
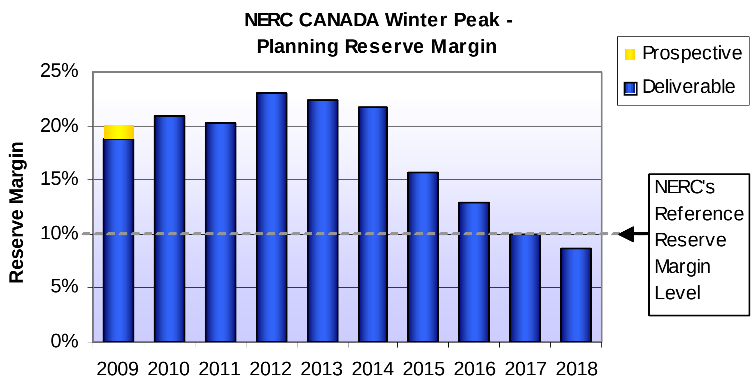


Figure Metrics 2



[51] For more information on the NERC Reference Reserve Margin Level, see *Terms Used in This Report*.

ALR 1-4. BPS Transmission Related Events Resulting in Loss of Load

Background

BPS Transmission Related Events Resulting in Loss of Load metric tracks BPS transmission-related events, which result in loss of load. It allows planners and operators to validate their design and operating criteria by identifying the number of instances when there is unacceptable performance occurs.

An "event" is an unplanned transmission disturbance that produces an abnormal system condition due to equipment failures and/or system operational actions, which result in the loss of firm system demands for more than 15 minutes, as described below[52]:

- Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
- All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50 percent of the total customers being supplied immediately prior to the incident, whichever is less.
- Firm load shedding of 100 MW or more to maintain the continuity of the BPS reliability.

Limitations

The metric counts the number of the events within a year and, therefore, does not provide an indication of their severity and impact. Namely, total MW loss and duration of events are not reflected.

Assessment

Figure Metrics 3 shows the number of BPS transmission-related events resulting in loss of firm load[53] from 2002 to the second quarter of 2009. The total number of the events has decreased from 2005 to 2008. Since the sample size is small, caution should be used on drawing conclusions.

[52] Details of event definitions are available at http://www.nerc.com/files/EOP-004-1.pdf.

[53] The metric source data may require adjustments to accommodate all the different groups for measurement and consistency as OE-417 is only used in the US..

Figure Metrics 3

ALR 2-4. Average Percent Non-Recovery of Disturbance Control Standard (DCS) Events

Background

The Disturbance Control Standard Events metric measures the Balancing Authority or Reserve Sharing Groups' (RSG) ability to use contingency reserve to balance resources and demand while returning the interconnection frequency within defined limits following a Reportable Disturbance.[54]

The relative percentage provides an indication of performance measured at a BA or an RSG. NERC Standard BAL-002 requires that a BA or RSG report all DCS events and non-recoveries to NERC.

Limitations

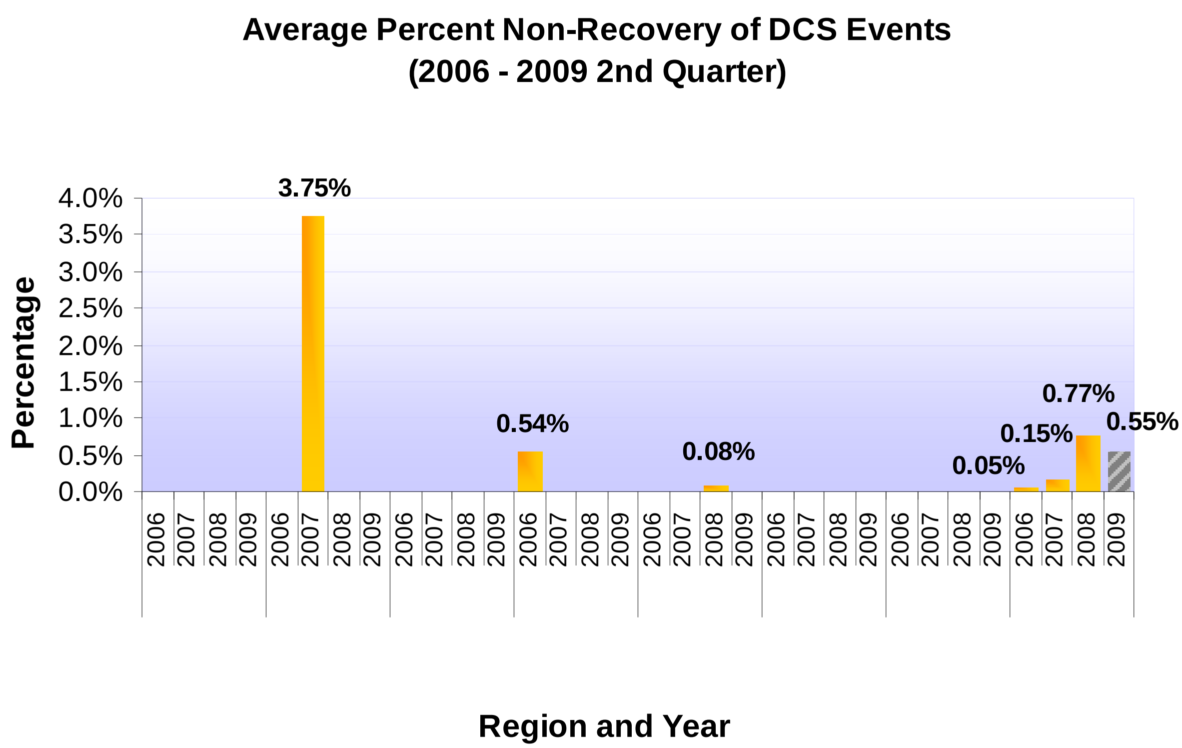
The metric aggregates the number of events based on reporting from individual Balancing Authorities or Reserve Sharing Groups. It does not provide a measure of the severity of these DCS events cannot be compared over time.

[54] Details of the Disturbance Control Performance standard and Reportable Disturbance definition are available at http://www.nerc.com/files/BAL-002-0.pdf.

Assessment
Figure Metrics 4 shows the average percent non-recovery of DCS events from 2006 to the second quarter of 2009.

MRO
One DCS event within the MRO Region did not fully recover to 100 percent within 15 minutes during 2007. The MW amount called on for this contingency reserve was understated and insufficiently low. However, there was sufficient contingency reserves available in the Midwest ISO Contingency Reserve Sharing Group at the time of this event and the reserves were deliverable. The 3.75 percent non-recovery shown for the MRO Region for 2007 does not indicate that there was a lack of contingency reserves or an inability to deliver contingency reserves during this event or any other event within the MRO Region in 2007.

Figure Metrics 4



ALR 2-5. Disturbance Control Events Greater than Most Severe Single Contingency

Background

Disturbance control events greater than Most Severe Single Contingency metric identifies the number of disturbance events that exceed the Most Severe Single Contingency[55] (MSSC) and is specific to each BA. BA or RSG report disturbances greater than the MSSC on a quarterly basis. The results help validate current contingency reserve requirements. Investigations of these events document how often these contingencies occur. The MSSC is determined based on the specific configuration of each system and while there are general guidelines, MSSCs vary in significance and impact on the BPS.

Limitations

The metric only reports the number of DCS events greater than MSSC without regards to the size of a BA or RSG. Therefore, equal number of the events would show the same trend line for small entities, as for large entities. Therefore, the severity and impact of the events can not be compared over time.

Assessment

Figure Metrics 5 represents the number of DCS events that are greater than the MSSC from 2006 to the second quarter of 2009

SERC

For SERC, Disturbance Control Standard determinations are based on 80% of the MSSC for each of the 30 Balancing Authorities in the SERC region. Some of these Balancing Authorities are small and, as a result, the MSSC's are smaller compared to those in other regions. This factor results in a greater number of reported events for SERC and makes this metric not comparable from region to region.

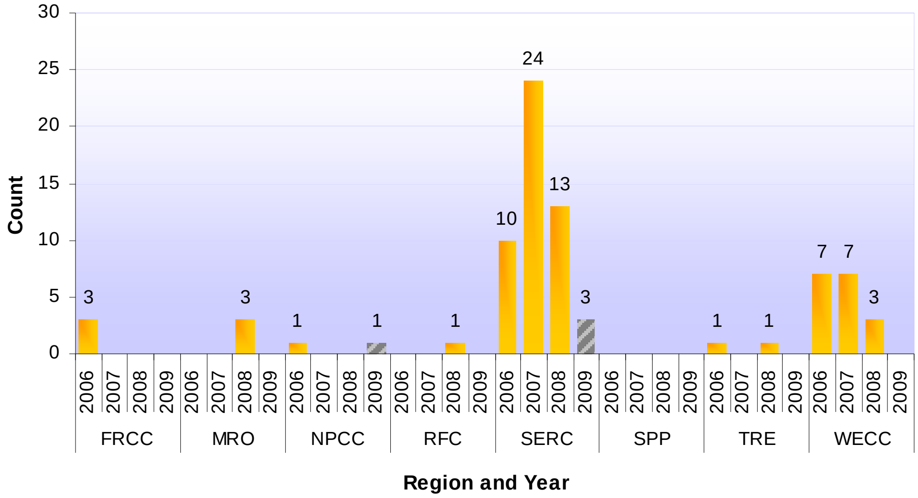
WECC

For WECC, Disturbance Control Standards are more stringent, which require reserves over and above MSSC. The details are available from WECC Standard BAL-002-WECC-1: http://www.nerc.com/files/BAL-002-WECC-1.pdf

[55] Details of the most severe single contingency determination process are available at http://www.nerc.com/files/BAL-002-0.pdf.

Figure Metrics 5

Disturbance Control Events Greater Than Most Severe Single Contingency (2006 - 2009 2nd Quarter)



ALR 4-1. Percent of Automatic Outages caused by Failed Protection System Equipment

Background

Percent of Automatic Outages caused by Failed Protection System Equipment metric measures the relative performance of protection systems (both generator and transmission) on the BPS.

The percentage of automatic transmission outages caused by failed protections systems provides an indication of the relative performance of protection system operations, specifically compared to correct protection system operations as a ratio of total protection system operations. This metric could also be expanded in the future to track human error and equipment failure misoperations (e.g., percent of misoperations caused by human error and equipment failures).

To determine if a misoperation has occurred requires that all operations be reviewed by transmission/generator owners. Therefore, the total number of operations should already be known, and could be reported (in total or possibly broken down further by voltage level). Misoperations are currently reported to the Regional Entities for compliance to PRC-003, 004 and 016, but the total number of operations is not. The total number of operations should be available when these three PRC standard revisions become effective as endorsed by the PC.[56]

In the interim since the TADS data provides the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[57] for 200 kV and above, the current metric is defined as the Percent of Automatic Outages caused by Failed Protection System Equipment.

---

[56] The recommended changes by the Special Protection and Control Subcommittee can be viewed at http://www.nerc.com/docs/pc/Draft_PC_Minutes_June_2009_06-23-09.pdf.

[57] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

Limitations

Interim Measure: In the interim, since the TADS data provides the total number of automatic transmission system outages and the number of outages caused by failed protection system equipment[58] for 230 kV and above, the current metric is defined as the Percent of Automatic Outages caused by Failed Protection System Equipment. The correct protection system operations will be used once the total number of protection system operations can be obtained from the revised PRC-003, 004 and 016 standards.

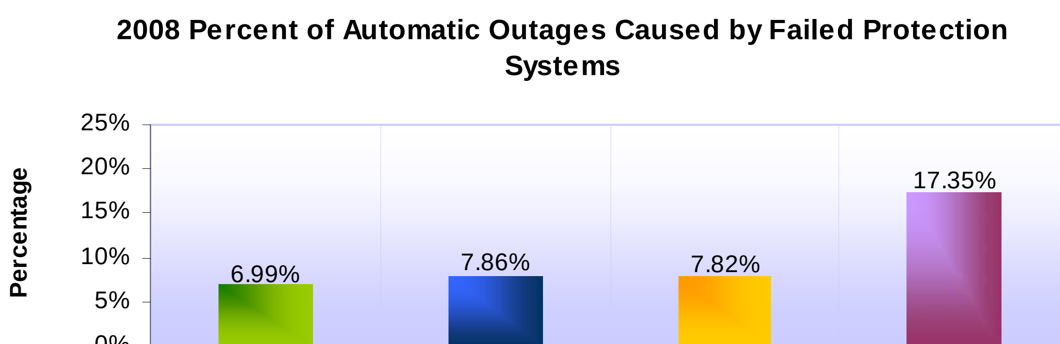
Assessment

Figure Metrics 6 shows the percent of automatic outages caused by failed protection system equipment reported in 2008.

765 kV

Since the TADS contains one year of data, the statistical sample is small and caution should be used when drawing conclusions. The total number of 765kV outages is relatively small (81 total), compared with other voltage classes, which have more than 4000 reported outages and over 350 protection equipment failures. As three to five years of data is available, a rolling average failure rate can be used to represent a statistical trend line.

Figure Metrics 6



	230 kV	345 kV	500 kV	765 kV
Failed Protection Outages	189	122	50	17
Other Automatic Outages	2515	1430	589	81
Percentage	6.99%	7.86%	7.82%	17.35%

[58] TADS Data Reporting Instruction Manual can be viewed at http://www.nerc.com/docs/pc/tadstf/Ph_I_Data_Reporting_Instr_Manual_112108.pdf.

ALR 6-2. Energy Emergency Alert 3 (EEA 3)

Background

Energy Emergency Alert 3 (EEA 3) identifies the number of times EEA 3s are issued. EEA3 events are firm-load interruptions due to capacity and energy deficiency. EEA 3 is currently reported to NERC and a database is maintained of these events. EEA 3 is defined in NERC Standard EOP-002-2.[59]

The frequency of EEA 3s over a period of time provides an indication of performance measured at a BA level or interconnection level. As historical data is gathered, trends in future reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. This metric will also provide value in developing a correlation between EEA events and Reserve Margins for future planning recommendations. There should be no economic factors included in use of EEAs. However, in certain Regions and under certain reserve sharing agreements the industry has adapted this metric in a way, which requires EEA declarations in order to implement certain commercial or tariff processes. In those Regions where EEA3 events are implemented under tariff or contract requirements for economic purposes, these have been eliminated from the data record. This was not the intended purpose of the EEA process and unfortunately has the effect of making a reliability indicator into an economic tool for operation of the system.

Limitations

The metric counts the number of EEA3 declarations. Therefore, their severity and impact (e.g. event load shedding and durations) can not be compared over time.

Assessment

Figure Metrics 7 shows the number of EEA 3 events between 2006 and the second quarter of 2009 at a Regional level.

<u>SPP</u>

The SPP RC has issued more EEA 3s in 2009 than previous years and anticipates that the Acadiana Load Pocket[60] will be of concern for the remainder of the 2009 summer. SPP is working with each entity in the area to resolve the issues and protect the load in the area. As a long-term solution, the SPP ICT facilitated an agreement with members in the Acadiana pocket to expand and upgrade electric transmission in the area. The joint project includes upgrades to certain existing electric facilities as well as the construction of new substations, transmission lines, and capacitor banks, at a total estimated cost of approximately $200 million. Each utility is responsible for various components of the project work. All upgrades are expected to be completed between 2010 and 2012. The detailed expansion and upgrades are available at http://www.spp.org/publications/SPP_Acadiana_news_release_1-19-09.pdf.
When completed, these upgrades will address the congestion issues currently experienced in the Acadiana area.

---

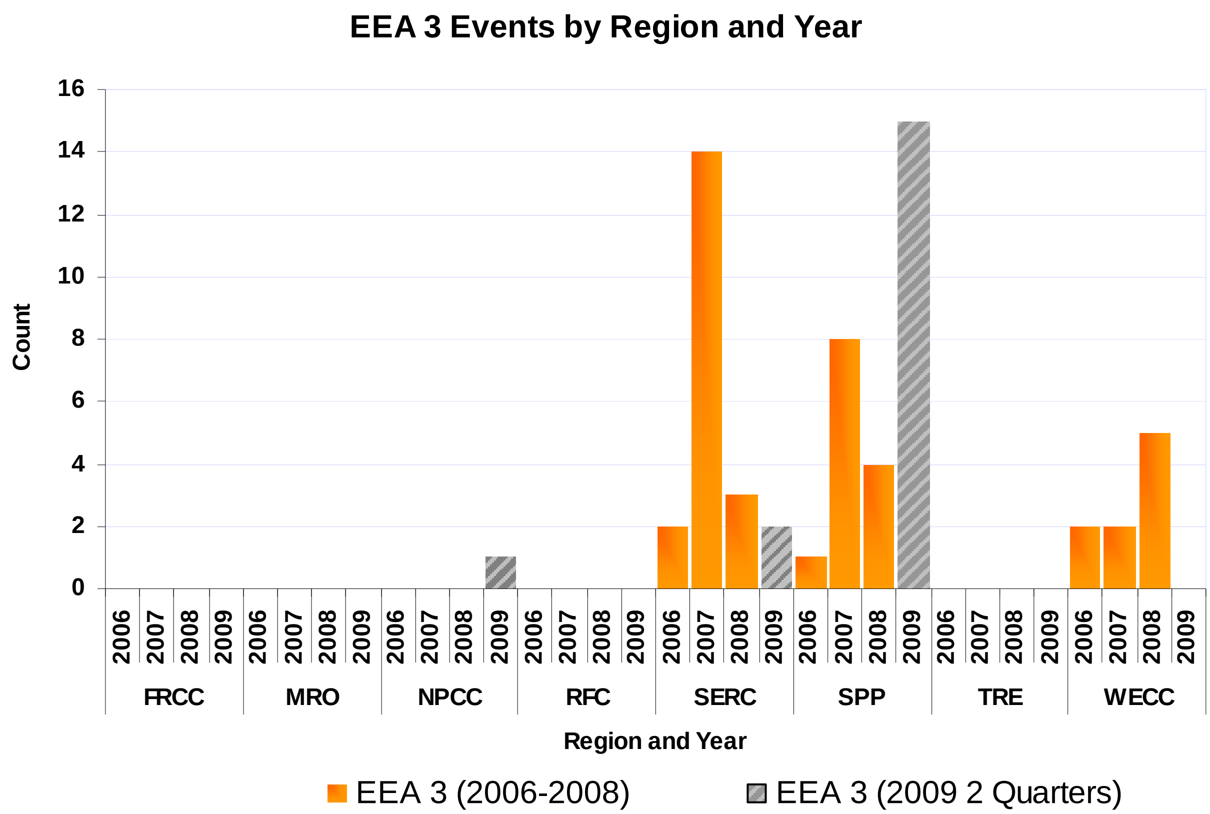
[59] EEA 3 definition is available at http://www.nerc.com/files/BAL-002-0.pdf

[60] Refer to SPP's Regional Assessment in 2009 Long-Term Reliability Assessment for mode details of adequacy issues in the Acadiana Load Pocket.

<u>SERC</u>

The high numbers of EEA3s for SERC in 2007 were the result of peak system conditions and have not been repeated in recent periods. Summer 2007 was the period when the last Regional peak occurred. SERC contains a number of relatively small Balancing Authorities generally smaller as compared to those in other regions and in general makes this metric not comparable from region to region. The trend in the metric is favorable.

Figure Metrics 7



ALR 6-3. Energy Emergency Alert 2 (EEA 2)

Background

Energy Emergency Alert 2 (EEA2) metric measures the number of events BAs declare for deficient capacity and/or energy during peak load periods, which may serve as a leading indicator of energy and/or capacity shortfall in the adequacy of the electric supply system. It is a leading indicator in that it provides a sense of the frequency of precursor events to the more severe EEA3 declarations.

The number of EEA2 events, and any trends in their reporting, indicates how robust the system is in being able to supply the aggregate load requirements. The historical record includes DSM activations and non-firm load interruptions per applicable contracts within the EEA alerts. These Demand Resources are legitimate resources to be called upon by BAs and are not of direct concern regarding reliability. As data is gathered on a going-forward basis, future reports will provide an indication of either decreasing or increasing adequacy in the electric supply system. EEA events calling solely for activation of DSM (controllable or contractually prearranged demand-side dispatch programs) or interruption of non-firm load per applicable contracts will be excluded from the metric, as demand response is a legitimate resource. This metric will also provide value in developing a correlation between EEA events and reserve margins for future planning recommendations.

Limitations

Future data reporting will be modified to add additional information on what actions are being taken in EEA2 events to ensure DSM and non-firm load interruption are excluded from the metric.

Through the RMWG the PC is proposing that data reporting processes be modified to add additional information on what actions are being taken in EEA 2 events to ensure DSM and non-firm load interruption are excluded from the metric.

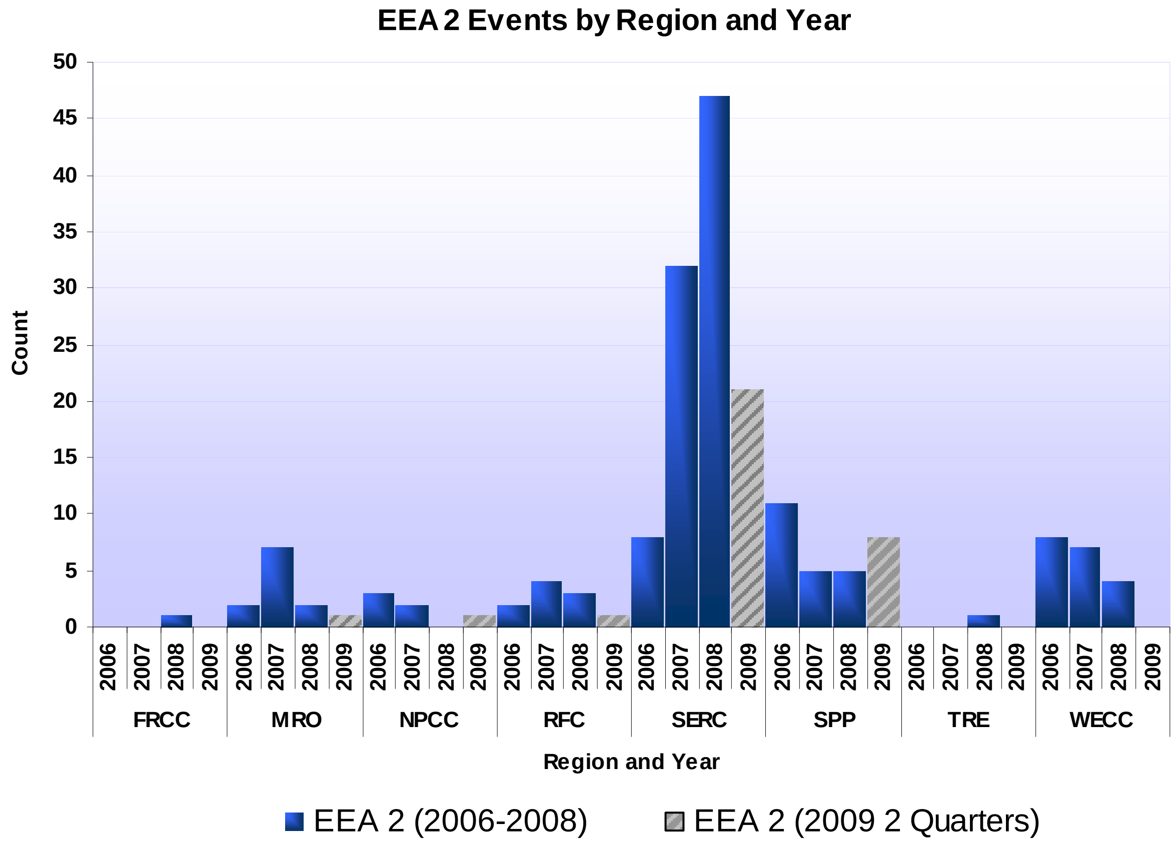
Assessment

Figure Metrics 8 shows the number of EEA2 events between 2006 and the second quarter of 2009 unadjusted for DSM activations.

SERC

SERC contains a number of relatively small Balancing Authorities generally smaller as compared to those in other regions and in general makes this metric not comparable from region to region.

Figure Metrics 8



Emerging and Standing Reliability Issues

Introduction

Each year, the ten-year *Long-Term Reliability Assessment* forms the basis for the NERC reference case. This reference case incorporates known policy/regulation changes expected to take effect throughout the ten-year timeframe assuming a variety of factors such as economic growth, weather patterns and system equipment behavior. A set of scenarios can then be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure any significant changes in bulk power system required to maintain reliability. This follows the process outlined in the *Reliability Assessment Guidebook*, version 1.2, dated March 19, 2008[61] developed by the Reliability Assessment Improvement Task Force in their report to the Planning Committee in September, 2008.[62]

Emerging and Standing Issue Risk Assessment

Background - Risk assessment of standing and emerging issues measures their perceived likelihood and potential consequences. To qualify for consideration, emerging issues must affect bulk power system reliability based on the following criteria: 1) Exists for more than a single year in the ten-year study period, 2) Impacts reliability no sooner than three years into the future to allow sufficient time for analysis, and 3) Impacts reliability across at least one Regional footprint and is not a local or subregional reliability issue.

During the June 9-10, 2009, Planning Committee meeting, the Committee reviewed and approved issues for subsequent risk assessment with the requirement that issues that already being addressed by a Committee subgroup be called "Standing Issues" and addresses such issues with summaries only while referencing existing Committee subgroup work. All other issues are called "Emerging Issues."

Risk Assessment – After endorsing both the Standing and Emerging issues identified by three of its subgroups (Transmission Issues, Resource Issues and Reliability Assessment Subcommittees), the PC prioritized the resulting issues based on risk, defined as their likelihood and consequence, and categorized each issue as high, medium, or low. This risk assessment was evaluated for two timeframes: 1-5 years and 6-10 years.

2008 Emerging Issue Update

In the *2008 Long-Term Reliability Assessment*, NERC's Reliability Assessment Subcommittee and staff identified seven emerging issues for use in the Planning Committee's (PC) Risk Assessment. Those issues are listed below with a brief summary update.

---

[61] http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf (page 55)
[62] http://www.nerc.com/files/Reliability%20Improvement%20Report%20RAITF%20100208.pdf

- ***Greenhouse gas reductions*** – Greenhouse gas reduction related legislation remains a high concern issue. NERC's Reliability Impacts of Climate Change Task Force (RICCITF) has subsequently been formed to address this issue and has provided input to the *Greenhouse Gas Legislation Standing Issue* section of this report. Greenhouse gas reduction was prioritized again this year by the PC (see below).

- ***Fuel storage and transportation*** – Fuel storage and transportation reliability considerations have decreased over the last year due to current economic conditions resulting in reduced demand for fuel. However, fuel shortages present a perennial concern for system reliability and are summarized in the *Generation* section. Detailed analysis is also provided in the *Fuel Supply Analysis: Coal, Natural Gas and Uranium* section. This issue was not prioritized this year by the PC.

- ***Rising global demand impacts for electric power equipment*** - Reliability concerns related to rising global demand for energy and equipment have decreased significantly over the last year due to decreased global economic activity. NERC will continue to monitor this issue with particular attention to a potential surge in demand for equipment and raw materials in Brazil, Russia, India, and China coinciding with global economic recovery. This issue was not prioritized by the PC this year.

- ***Increased adoption of demand-side and distributed generation resources*** – Demand-side management programs continue to grow and further review of this issue is provided in several sections of this report including *Demand*, and the emerging issue titled, *Economic Recession*. Distributed generation was not specifically addressed in this report but remains an issue that NERC is monitoring.

- ***Transmission for the 21st century***– Significant transmission additions are planned through 2018 and addressed in *Transmission*. Two emerging issues in this report involve transmission siting. *Transmission Siting* presents general issues related to siting and *Variable Generation* explores transmission needs required for the integration of new variable resources.

- ***Water availability and use*** **–** Demand for water is increasing in North America and it is a vital resource requiring careful management. Thermal power plants require sufficient levels and quantities of water for cooling. Understanding the industry's role in water use and the implications of reduced water availability on bulk power system reliability requires careful study.[63,64] This issue was not prioritized by the PC this year, though NERC will continue to monitor it.

- ***Mercury emissions regulations*** **–** Uncertainty remains with the long-term outcome of the EPA's Clean Air Mercury Rule and its possible impacts on reliability. This issue was not prioritized by the PC this year, though NERC will continue to monitor it.

[63] http://www.nerc.com/files/NERC_SRA-Retrofit_of_Once-Through_Generation_090908.pdf
[64] http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml

2009 Reliability Issues Summary

NERC's Reliability Assessment Subcommittee (RAS), Resource Issue Subcommittee (RIS), Transmission Issues Subcommittee (TIS), and staff identified 14 issues for use in the Planning Committee's (PC) 2009 Risk Assessment:

Emerging Issues
- *Economic Recession*[65] *– Demand Uncertainty*
- *Economic Recession – Demand Response and Energy Efficiency*
- *Economic Recession – Rapid Demand Growth after Flat Period*
- *Economic Recession – Infrastructure Impacts*
- *Transmission Siting*
- *Energy Storage*
- *Workforce Issues*
- *Cyber Security*

Standing Issues (related to ongoing committee subgroup work):
- *Variable Generation – Transmission*
- *Variable Generation – Ancillary Services*
- *Variable Generation – Operational Issues*
- *Greenhouse Gas Initiatives*
- *Reactive Power*
- *Smart Grid and AMI*

Ranking and Risk Evolution - The risk assessment survey was completed by industry stakeholders represented on the NERC Planning Committee during the summer of 2009. Figure Issues 1 provides the risk vectors for each of the emerging/standing issues for both the one to five (1-5) year and six to ten (6-10) year timeframe. Several vectors indicate significant risk change from the 1-5 to 6-10 year timeframes, such as Energy Storage.

In totality, the ranking of the 2009 Emerging and Standing issues suggest the electric power industry is being asked to deal with many multifaceted, interconnected issues simultaneously. The industry is in transformation, where many interrelated issues present complex risks to bulk power system reliability from across the planning, design and operational spectrum. Overall, the vectors suggest more than the relative importance of individual issues or a general increase in risk presented by them. This is especially true as all but one vectors point to a higher risk from the 1-5 to 6-10 year timeframes. Only the Economy Issue risk and likelihood is reduced perhaps indicating the stakeholders believe some of the uncertainty associated with the current recession will be resolved or better understood during the next five years.

[65] These Emerging Issues were originally titled "Economic Downturn" but renamed to "Economic Recession" to accurately reflect the broad reduction in economic activity and marked change in the business cycle.

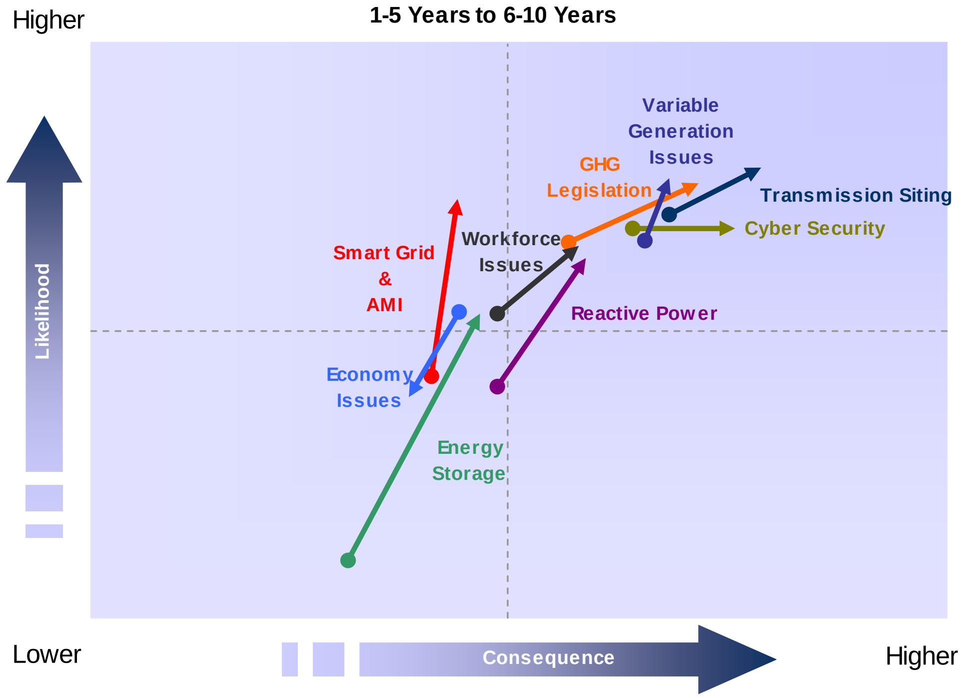


Figure Issues 1: Emerging and Standing Issues
1-5 Years to 6-10 Years

Note: The colors (of the arrows) in Figure Issues 1 were randomly chosen to differentiate overlapping arrows—the colors do not represent additional data or special meaning. Arrows point from the '1-5 Years' ranking to the '6-10 Years' ranking.

Similar issues are grouped, below, and summary reviews are provided in the following sections of this report.

Emerging Issues

- Economic Recession
  - Demand Uncertainty
  - Demand Response and Energy Efficiency
  - Rapid Demand Growth after Flat Period
  - Infrastructure Impacts
- Transmission Siting
- Energy Storage
- Workforce Issues
- Cyber Security

Standing Issues

- Variable Generation (Integration of Variable Generation Task Force)
  - Transmission
  - Ancillary Services
  - Operational Issues
- Greenhouse Gas Legislation (Reliability Impacts of Climate Change Initiatives Task Force)
- Reactive Power (Transmission Issues Subcommittee)
- Smart Grid and AMI (Smart Grid Task Force)

2009 Emerging Issues

Economic Recession

The economic recession that began in 2007 has become a major global recession and has had an indelible impact on the electric power industry. While there is currently substantial uncertainty on the time, rate, and breadth of an economic recovery in the coming years, it is certain that its eventual arrival may present risks and challenges to the bulk power system on several levels. Here, four issues are explored in greater detail:

1. Demand Forecast – *The recession has caused significant impacts in demand forecasts.*

2. Growth in Demand Response and Energy Efficiency Programs – *Economic difficulties that drive new business opportunities and incent new resource programs may drive steep increases in these programs (and accompanying reliance upon them) but vigilance will be required to ensure they are available when needed for reliability.*

3. Rapid Demand Growth after a Flat Period – *An economic recovery will occur (eventually), but it is uncertain when it will happen and how fast it will occur—if the economy recovers quickly, the bulk power system must be ready to balance supply and demand while maintaining bulk power system reliability.*

4. Infrastructure – *Project financing uncertainty—in addition to reduced revenues—may thwart necessary infrastructure investments and impair long-term reliability.*

Demand Forecasts

The recession that has taken place throughout North America affects electric demand to varying degrees, depending on the Region and customer base. Long-term effects (structural) of the current recession shall remain so that decline in short and long term load forecasts is likely. The contribution of the economic component is a significant factor in load forecasting. Typically, the electric use in North America closely tracks the performance of the Gross Domestic Product (GDP) along with Regional employment and income. The severity of the current recession, coupled with the uncertainty of when a recovery will be realized, renders near-term load estimates particularly suspect; however, data suggests in the first two to three year period, economic uncertainty will prevail, with a recovery pattern probably quite different from previous slowdowns when peak demand was less impacted than energy use.

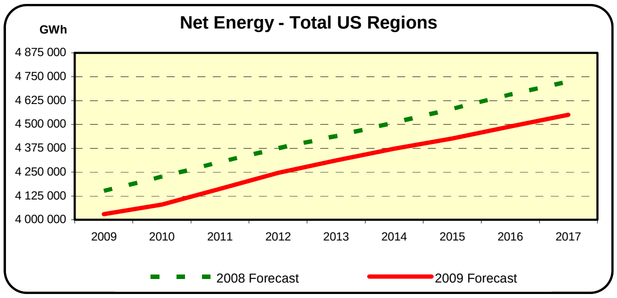
Whether changes are either cyclical or structural, or both, demand forecasts are entering a new uncertain phase and close monitoring of the recession's influence on electric demand is recommended.

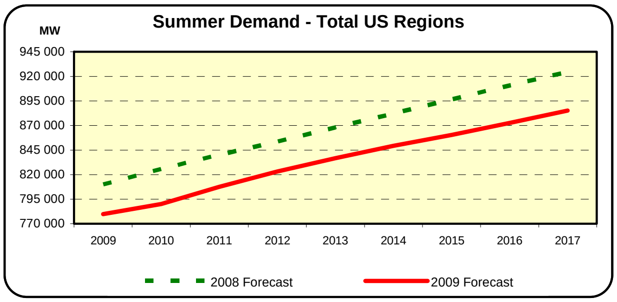
Background

A severe economic recession has taken place throughout North America. Structural long-term effects of this recession are expected to remain, so a decline in short and long term load forecasts is likely. Accordingly, NERC's *2009 Long-Term Reliability Assessment* forecast shows that this current recession impacts electric demand at varying degrees depending on the Region. Not all changes between 2008 and 2009 forecasts can be attributed to the economic recession.

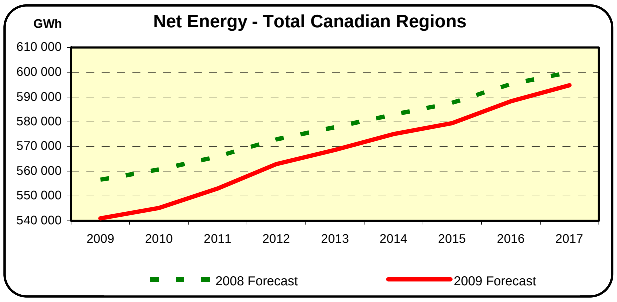
There is variation in the year-by-year path of each Region's forecast along with comparison to last year's forecast. All regions are impacted by the recession, but each in its own way.

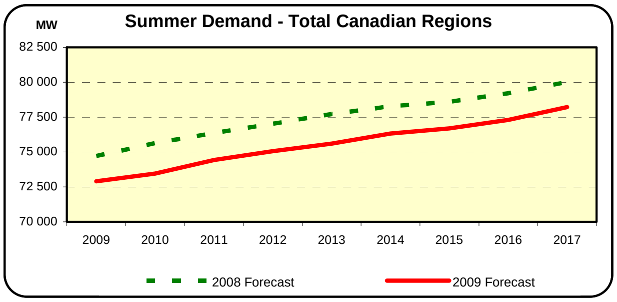
For the U.S., the 2009 forecasts include an average downward revision for the 2009-2017 timeframe of about -3.4 percent in terms of net energy level and -4.1 percent in terms of summer demand when compared to the 2008 forecast.



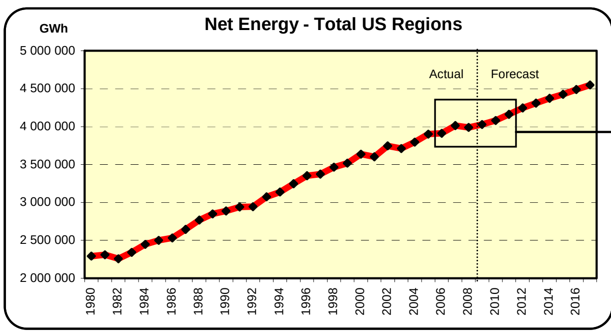


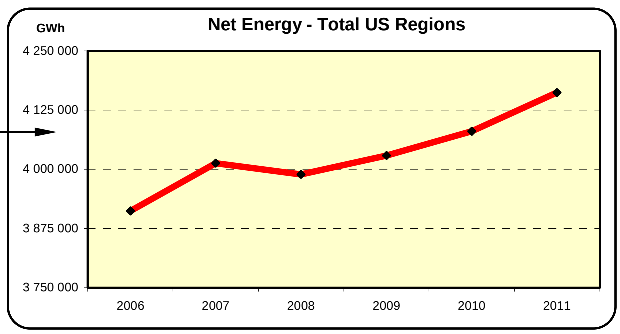
In Canada, this revision is about -1.8 percent (from -2.9 percent in 2009 to -0.9 percent in 2017) in energy and -2.6 percent in summer peak demand for 2017.

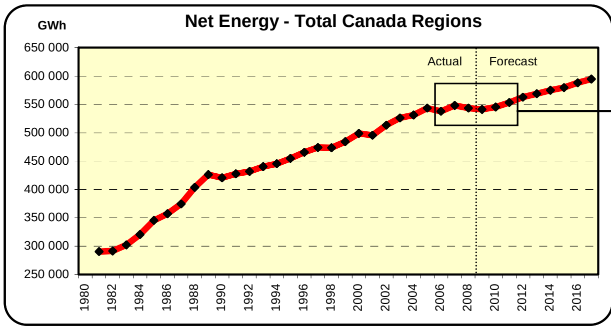


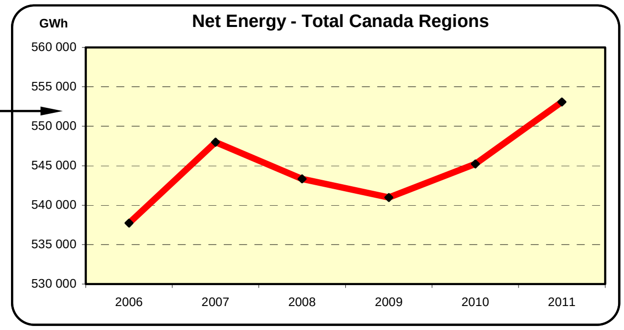


As anticipated, the 2009 forecast in this year’s report includes the impact of a deep recession, while the recovery pattern is expected to be no different from previous recessions for both U.S. and Canada (as showed below merging historical data and this year's forecast, regions assume a recovery as soon as 2009 for the U.S. and 2010 for Canada).







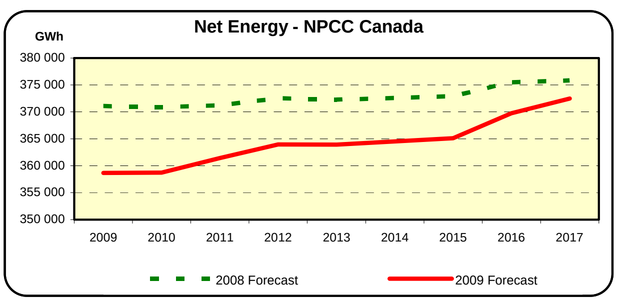


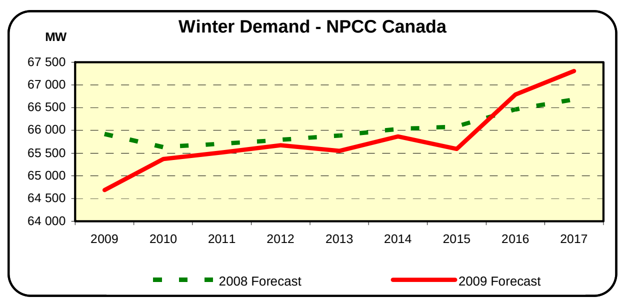
The analysis of the NERC Regional forecasts for this year's report also provides a good indicator on expected impacts within each geographical area. After reviewing individual results, some general conclusions can be drawn:

- There are significant differences among regions in terms of energy and peak demand impacts. More specifically, lower growth rates can generally be observed for each U.S. Region and slightly higher growth rates are however registered in Canada.
- Unlike first expectations, peak demand is affected more than energy, especially for U.S. winter and Canadian summer peaks.
- In terms of level, there is no sharp bounce back anticipated after the recession in any regions.

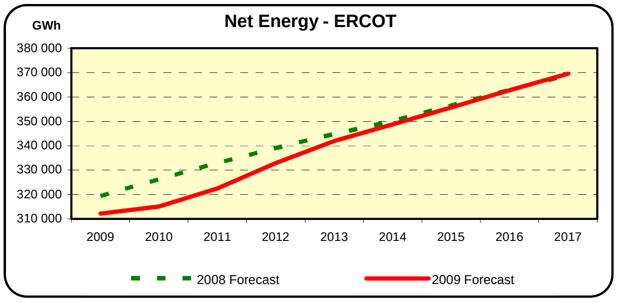
Several Regions and subregions with notable demand patterns are reviewed below.

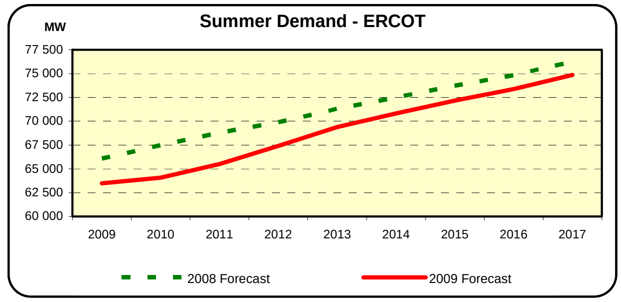
- As shown before and despite a long and slow pattern, Canadian regions' forecasts tend to recover closer to the 2008 forecast level than the U.S. This is especially true for NPCC-Canada.



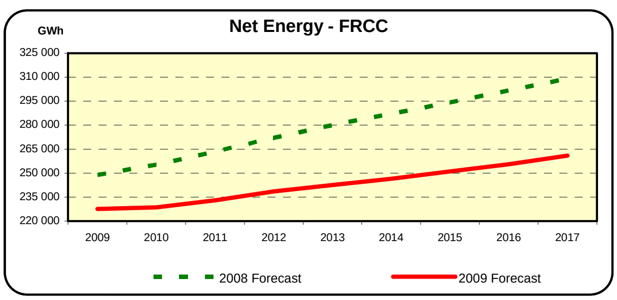


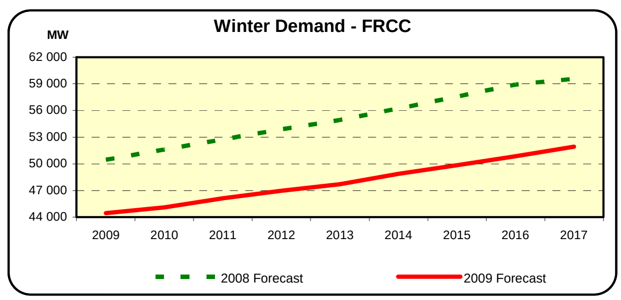
- This year's ERCOT forecast grows closer to the last year's than all other regions with a complete recovery in terms of energy level by the end of the 2009 to 2018 period. From 2009 to 2017, the average annual growth rate for the system peak of ERCOT's forecast last year was 1.8 percent and the growth rate this year is 2.1 percent. The higher eight-year growth rate in this year's forecast is fuelled by the projected strong recovery from the current economic recession reflected in the economic forecast in this Region after 2010.



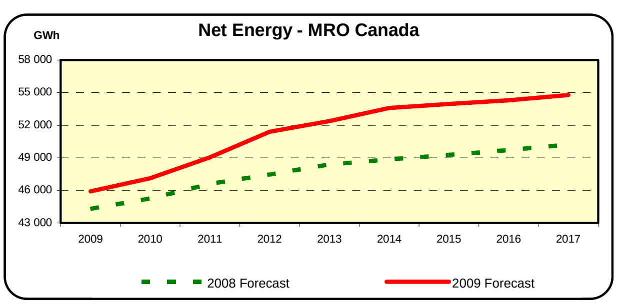


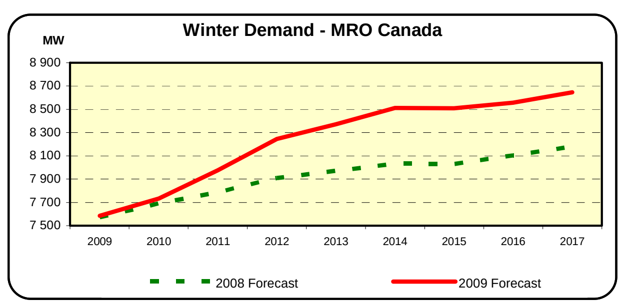
- Relative to the 2008 forecast, FRCC's forecast shows the largest decrease of all the regions with an expected net energy adjustment varying from -9.4 percent in 2009 to -18.4 percent in 2017. The summer peak forecast for this Region exhibits an average annual growth rate of 1.7 percent over the next eight years compared to last year's growth rate of 2.2 percent. This reduction is attributed to a decrease in economic development expectations in Florida along with an increase in demand side management coupled with expected higher electricity costs.





- There is a drop in energy and peak demand for all regions but one: the MRO Canada's new forecast is significantly higher than last year's and also grows much faster for the entire period, both in energy and in peak demand.





Conclusion

Whether cyclical and/or structural negatives result, demand forecasts are entering a new changing and uncertain phase and not all changes between this and last year's forecasts can be attributable to the current economic recession.

A recovery pattern not much different from previous slowdowns is anticipated by the majority of the regions. However, in the first two- or three-year period, major economic uncertainty will prevail. Additional uncertainty about deferral or cancellation of major industrial projects will not be easily quantifiable and will make both short and long term demand forecasting more challenging than in a steady economic growth cycle.

The current major economic recession has already negatively impacted the load forecast and will drive up short-term North American planning Reserve Margins. In the longer run, generation projects and transmission infrastructure investment may also be affected. A close and continuous monitoring of the recession, its impact and the economic recovery for all regions is recommended for the next few months.

<u>Growth in Demand Response and Energy Efficiency Programs</u>

Beyond cyclical or structural issues, peak demand and energy forecasting is becoming more challenging in an economic and legislative environment that encourages increased use of Demand Response (DR) and Energy Efficiency (EE) programs. Several U.S. states have mandated that certain levels of either DR or EE, or both be phased in over the next 5 to 10 years. In most cases, detailed plans for achieving these targets are yet to be developed. Planners must recognize this increased uncertainty in their reliability studies. An additional challenge is quantifying the impact of DR and particularly EE programs on peak-demand. EE programs target the reduction of energy use and the resulting impact on peak loads must be assessed to properly plan the electric power system.

Challenges related to DR forecasting include the need to develop accurate forecasts of:

- DR performance to ensure that adequate resources are installed to meet appropriate resource adequacy guidelines or standards.
- The aggregate amount of coincident reductions that can be obtained under varying weather conditions—if weather is actually the primary determinant of DR performance.
- The possible number of requests for customer response to DR signals. Such forecasts would allow for effective and informed decision making by potential demand-resource providers to provide these resources into the market.

The amount of DR and EE assumed in future years varies depending on different counting methods. The amount needs to recognize the DR and EE goals established by regulatory authorities but also needs to consider the likelihood of those goals being realized and their likely impact on peak demand. Inaccurate forecasts of peak demand due to uncertainty associated with future DR and EE programs can lead to several problems; failure to identify required facilities to maintain a reliable system, inadequate Reserve Margins, and transmission analyses failing to identify potential transmission reliability issues.

Depending on how aggressively demand resources are implemented and sustained in the NERC Regions, the penetration of these resources will provide many benefits, while, at the same time, bring many challenges. Efficiently integrating DR into the bulk power system while maintaining system reliability can challenge system planning processes, system and market operating processes, and electricity and computer hardware infrastructure. It also will require the development of effective integration methods that overcome some of the current challenges. Beyond the forecasting challenges of integrating large amounts of DR noted above, other challenges include the need to:

- Know the location of DR so that when activated, the response will have an expected outcome regarding operational metrics (voltage, line flows, etc.).
- Develop a reliable communications platform between the Balancing Authority Area operator and the DR providers to assure proper demand-response activations.
- Obtain accurate and descriptive performance data, using suitable definitions, to understand historical performance so that future performance can be estimated with a high degree of accuracy.
- Ensure that reliability is maintained without creating barriers to DR participation when there is a large penetration of DR resources in the bulk power system.

The NERC Demand Response Data Task Force is working to address some of these issues by working with stakeholders to develop better data collection procedures.

Rapid Demand Growth after Flat Period

As noted above, forecasting demand is difficult due to uncertainty in many of the input variables. Thus, no forecast can say with certainty how peak-demand and use will change over the coming years. A plausible demand growth projection involves flat to negative demand growth over the next 7 to 8 years followed by an abrupt change to normal or high demand growth. This type of situation is possible because of the uncertainty related to the confounded near-term effects of the economic slowdown, industrial load decline, increased conservation, Energy Efficiency (EE) increases, price-induced load reduction, and incentive-based demand reduction programs followed by a swift economic recovery and a waning impact over time for some demand-reducing programs.

The situation may include aggressive retirement of generation during the first 7 to 8 years, a consideration that generation manufacturing capacity would be idled during the low-growth period, and emission rules may be tightened in anticipation of continued low demand growth. As a result, generating capacity is retired to minimums only required for operational levels or required by regulation or markets. As future load is expected to be flat or low-growth, surplus generation is expected to have little possibility of future value and inhibit adequate investment.

The result of this demand growth pattern and generation changes may result in supply and demand balances that deteriorate quickly in the latter years of such a situation. Reliability can rapidly deteriorate in the last years of the planning horizon as demand increases rapidly and generation cannot be constructed quickly enough to respond.

Future studies of this situation include modeling low load growth with tight reserves no later than 7 years out followed by rapid growth with little ability to respond within the time horizon. This situation can illustrate the need to keep adequate generating reserves in case of load growth even if it is considered a low probability event.

Infrastructure

Some utilities are likely to decrease or delay transmission and generation construction plans in light of decreased demand (or lower growth rates), financing challenges, increased regulatory scrutiny, and rising operations costs. The consideration is whether decreases or delays will affect long-term reliability:

- *Demand* - Projects driven by load growth may not be justified when demand drops while staying relatively flat for more than one year.
- *Financing* - A major contributor to the current recession has been the tightening of the credit markets, posing a threat to the financing of major projects and can become a challenge in constructing needed resources. Financing and rate recovery issues may present problems implementing new generation, demand-side management and transmission projects potentially becoming a limiting factor for generation construction.

Transmission Siting

Province and State Renewable Portfolio Standards (RPS) will increase renewable resources located where wind power densities and solar development are favorable. U.S. federal RPS is also under consideration in Congress. Grid expansion is needed to support the dispersed nature of renewable resources. Finally, additional generation sources, especially large plants such as nuclear facilities, may require grid expansion to assure deliverability.

The limited timeframe provided to meet RPS mandates requires that the current siting and approval processes be expedited to ensure meeting mandated energy requirements. NERC Regions integrating wind resources have projected increases in transmission congestion, particularly when demand is low. As wind resources are less predictable and follow the availability of their fuel (wind) rather than dispatch instructions from operators or market based systems for traditional "controlled fuel" plants, different patterns in the use of transmission capacity can emerge from this new variable fuel paradigm. In some cases, renewable resource availability may not be correlated to demand, being available during the nighttime, for example, rather during daily peak periods. Energy storage may provide potential support by converting this energy to capacity (see *Emerging Issue: Energy Storage* section). Further, some Regions report challenges in managing the power system under high variability of wind resources and report the need to provide additional ancillary services (such as operating reserves) as specific challenges (see NERC's *2009 Summer Reliability Assessment*).[66]

Siting of new bulk power transmission lines brings with it unique challenges due to the high visibility, their span through multiple states/provinces and, potentially, the amount of coordination/cooperation required among multiple regulating agencies and authorities. Lack of consistent and agreed upon cost allocation approaches, coupled with public opposition due to land-use and property valuation concerns, have, at times, resulted in long delays in transmission construction. When construction is delayed, special operating procedures to maintain bulk power system reliability may be needed. For example, it took the American Electric Power Company

[66] Page 8, http://www.nerc.com/files/summer2009.pdf

fourteen years to obtain siting approval for a 90-mile 765 kV transmission project, while it required only two to construct it.

In the U.S., the intention of Section 1221 of the Energy Policy Act of 2005[67] was to simplify and streamline the siting process in order to build needed transmission in corridors demonstrating congestion. The provision is intended to resolve state and federal jurisdiction over siting authority. Section 1221 assigned the U.S. Department of Energy with the task of performing studies to identify areas or Regions where transmission limitations adversely affect consumers, and establish "national interest electric transmission corridor." These studies are conducted every three years.[68] The determination of national interest electric transmission corridors is based on five criteria.

1. The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity.
2. Economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and a diversification of supply is warranted.
3. The energy independence of the United States would be served by the designation.
4. The designation would be in the interest of national energy policy.
5. The designation would enhance national defense and homeland security.

The Energy Policy Act of 2005 also gave FERC "back-stop siting authority" for transmission and to issue permits for the construction or modification of transmission facilities in a "National Interest Electric Transmission Corridor." However, in Piedmont Environmental Council v. FERC,[69] the U.S. Court of Appeals, and Fourth Circuit reviewed several rulemaking decisions made by the Federal Energy Regulatory Commission and overturned a 2006 FERC rulemaking[70] interpretation of section 216 that Congress in Energy Policy Act 2005 added to the Federal Power Act.

The decision to limit FERC's siting authority will lengthen the permit issuing process and cause new transmission projects, in particular multiple-state or Regional projects from moving forward in step with the RPS mandates. Therefore, new transmission, including transmission in the DOE's designated "National Interest Electric Transmission Corridors" can be delayed or halted by states, increasing the difficulty to site bulk transmission, including those projects focused on unlocking location constrained renewable generation. This creates a potential congestion issue and challenges the economic viability of new generation projects. The inability to site and construct transmission can challenge bulk power system reliability in Regions/subregions that are retiring generation or out-growing their existing generation and are relying on new transmission to serve customers from remote generating resources.

---

[67] http://www.epa.gov/oust/fedlaws/publ_109-058.pdf
[68] http://nietc.anl.gov/
[69] http://pacer.ca4.uscourts.gov/opinion.pdf/071651.P.pdf
[70] http://www.ferc.gov/whats-new/comm-meet/111606/C-2.pdf

Energy Storage

Energy storage systems can benefit bulk power system reliability by storing energy capacity or to provide ancillary services. The introduction of significant amounts of variable generation resources, like wind and solar, can provide large amounts of energy, while not necessarily at the time it is most needed. Further the variability and uncertainty of their fuel source (wind or sun), increases the need for more flexibility in the bulk power system to maintain reliability. Several energy storage technologies are becoming more practical. While most of the energy storage technologies available today have existed for years or decades, higher energy prices, a requirement for better system reliability, and lower engineering and fabrication costs have increased the viable existing technologies.

There are very few ways to store electric energy on the scale necessary for the bulk power system and most systems in use today rely on storing mechanical energy for conversion into electricity. For example, hydro pumped-storage plants store a large amount of energy by pumping water up to a reservoir when excess energy is available and then rely on gravity to run water back through the plant to generate electricity when the energy or capacity is needed (i.e., during peak demand periods). Hydro pumped storage has a round trip energy efficiency of 70 to 85 percent.[71] Compressed air energy storage (CAES) units operate in a similar manner by compressing air into a large tank or underground cavern, recovering the energy by releasing the compressed air. Some CAES (hybrid) units include a generator connected gas-fired combustion turbine. Thus, CAES is a hybrid of energy storage and gas power production, requiring 30 to 40 percent of the gas used for traditional gas turbines.[72] There is one operational 110 MW CAES unit in Alabama. A number of projects are under development. For example, one 2,700 MW unit in Ohio,[73] and a 269 MW unit[74] in Iowa.

Large-scale electric battery-based electricity storage is becoming commercially viable and is being deployed to provide multiple benefits in a given application. AEP deployed its first 1 MW (7.2 MWh) sodium-sulfur battery storage project in 2006, justified by deferral of distribution system expansion. Since then, AEP deployed six more megawatts of sodium-sulfur batteries in three different states. The distribution circuit for each of these new installations is equipped with intelligent reclosers that, during a power outage, can isolate a variable portion of the feeder load (hundreds of customers) thereby providing electric service from the battery.

A one megawatt lithium-ion battery system for regulation was installed on the PJM system and certified by PJM. The energy storage capability is smaller (250 kWh) than the multi-megawatt batteries mentioned above and uses battery technology similar to the plug-in electric hybrids. The installation participates in PJM's Regulation Market becoming the first advanced lithium-ion battery energy storage system certified to provide regulation.

---

[71] http://www.electricitystorage.org/site/technologies/pumped_hydro/
[72] http://www.eere.energy.gov/de/cs_energy_storage.html#compressed_air
[73] http://www.opsb.ohio.gov/OPSB/cases/case.cfm?id=4070 and http://hydrodynamics-group.com/mbo/content/view/16/40/
[74] The Iowa Stored Energy Park: http://www.isepa.com/about_isep.asp

A two megawatt (500 kWh) lithium-ion battery system has been connected within the CAISO system for delivery of regulation.[75] The system has been in operation for testing since October 2008. It has been successfully responding to both unfiltered ACE and AGC signals. CAISO market infrastructure (software) and potential tariff changes are needed before this unit is a full commercial participant in the CAISO market. A 16 MW system, using the same lithium-ion technology as the 2 MW system deployed in the CAISO is being installed in Chile for provision of both regulation and operating (synchronized) reserves.

Flywheel storage has the ability to quickly generate or absorb power, well suited for regulation applications. A few examples include a 20 MW installation being built in New York to supplement the NYISO's regulation and, in 2008, Beacon Power began operating 1 MW flywheel technology energy storage system in ISO-NE.[76]

As an alternative approach to bulk energy storage, is to deploy small storage units on the secondary of its distribution transformers at residential service voltages (i.e., AEP). Each of these community energy storage units can serve several residential or light commercial loads. Once aggregated through the Advanced Metering Infrastructure, these community energy storage units, controlled collectively, act as a substation battery and improving reliability providing a backup source of energy near customers. The key element of community energy storage units is the use of highly efficient and compact plug-in electric vehicle (PEV) batteries.

While PEVs reduce fossil-fuel use, their successful integration of charging/discharging systems may offer energy storage benefits as well. However, PEV may be unavailable to lower peak demand since many will be in vehicular use or simply not connected to the grid. Therefore, the potential reliability benefits require very high PEV penetration. Further, substantial changes may be required for both distribution and bulk power systems to support two-way flow of energy along with advanced controls to support overall integration.

[75] http://www.a123systems.com/news_134

[76] http://216.139.227.101/interactive/bcon2008/pf/page_003.pdf

Workforce Issues

The "workforce shortage" considerations and its impending impact on reliability has been a recurring theme in NERC's recent *Long-Term Reliability Assessments*. In the 2006 *Long-Term Reliability Assessment*, NERC reported that, according to a Hay Group study, about 40 percent of senior electrical engineers and shift supervisors in the electricity industry would be eligible to retire in 2009, while the demand for engineers with a power background and other utility professionals has increased. At the same time, the number of students in the power engineering programs is dwindling in most universities. Further, the need for line-workers, power plant operators, maintenance/repair workers, and pipefitters/pipelayers has also increased. The Center for Energy Workforce Development (CEWD) has begun addressing these issues with its stakeholders by teaming with secondary and post secondary educational institutions and the workforce system to create workable solutions to address the need for a qualified, diverse workforce.[77] In the 2007 *Long-Term Reliability Assessment*, NERC revisited the issue and confirmed industry concern on the qualified workforce gap, ranking the aging workforce high on both likely to occur and likely to have a consequence on the reliability of the bulk power system.

Meanwhile, the demand for power workers to plan, maintain, and operate the bulk power system continued to increase with the growing need for new infrastructure investments in electric generation, delivery, and use technologies and the rising need for technology innovation driven by a world beset by new challenges. The need for new infrastructure and technology innovations means a steady, if not rising, need for well-trained engineers and workers. Further, universities, which drive for research and development funding, are also faced with the need to manage their power engineering faculty.

It will take a cooperative effort by industry and government to address this potential reliability issue. A number of activities are ongoing:

- In 2008, NERC, U.S. IEEE's Power and Energy Society (PES),[78] and the Power System Engineering Research Center[79] cosponsored a National Science Foundation (NSF) workshop on the subject.[80] NERC was also coordinating the efforts of various industry participants, the Idaho National Lab, and the Pacific Northwest National Lab in developing the North American Grid Center of Excellence, which would be an enhancement to existing operator/dispatcher simulators. The IEEE PES started an industry collaborative to develop industry strategies and solution to bridge the workforce challenge.[81] The Collaborative is working for the transformation of relationships among industry, government, and universities (1) to support ongoing activities that expand the pipeline of students, and (2) to build, enhance, and sustain university power engineering programs. In April 2009, the Collaborative released its report titled *Preparing the U.S. Foundation for Future Electric*

[77] http://www.cewd.org/
[78] http://www.ieee-pes.org/
[79] http://www.pserc.wisc.edu/
[80] http://www.pserc.wisc.edu/ecow/get/publicatio/specialepr/workforcec/2008_final_nsf_engineering_workforce_workshop_report.pdf
[81] http://www.todaysengineer.org/2008/Jul/PES.asp

Energy Systems: A Strong Power and Energy Engineering Workforce. This report contains a plan with recommended actions by industry, government, and educational institutions.[82]

- Program development to support university education is being funded by the National Science Foundation (NSF), Office of Naval Research, Electric Power Research Institute and University of Minnesota.[83]

While it may seem that the current economic recession would drive new workers into the industry to alleviate the workforce issues, in fact it will have a serious negative impact on the future workforce. This counter-intuitive reality is driven by several factors. As the demand for electricity decreases and access to capital for infrastructure investments tightens, utility companies may delay or cancel their resource and transmission projects and, to cope with short-term financial difficulties, often stop hiring new employees, reducing workforce, and encourage older employees to take early retirement. As the result, the gap in qualified employees will become more critical in the long-term, when the economy recovers.

The electric power industry is beginning to remedy the gap in qualified employees, but with the increased need to plan, design and operate the bulk power system to accommodate a variety of new technologies and processes facing industry, there still is substantial interest in developing workers needed to support industry needs.

Therefore, the workforce issue is expected to remain a concern in the coming years and will continue to pressure the industry.[84] The NERC Planning Committee currently ranks this issue as one with increasing likelihood and consequence to impact on bulk power system reliability.

Cyber Security

1. Uncertainty of the risk

There is considerable understanding of the risks associated with the production, transmission and use of electricity. When devices fail, adverse weather moves through, or unforeseen events take place, electric grid operators respond to compensate for the event.

These challenges are the physical challenges to the electric grid. There is significant knowledge of the mean time between failures for mechanical devices. Knowledge of the patterns of outages caused by weather can almost be predicted. The occurrences of the substation vandal, the unforeseen trip of a generator, or many other actions can been managed due to the way the system is either designed or operated.

With planning criteria that ensure the system can handle credible contingency and operating requirements, the grid has necessary robustness to deal with reasonable risks. This construct has

[82] http://www.pserc.org/docsa/US_Power_&_Energy_Collaborative_Action_Plan_April_2009_Adobe7.pdf
[83] http://www.ece.umn.edu/groups/power/
[84] http://www.todaysengineer.org/2008/Jul/PES.asp, p.15.

been validated through years of experience including the results of equipment failure, incorrect equipment operation, acts of nature and other physical world events.

With the new era of ever-increasing digital reliance and system complexity, there is an emergence of common vulnerabilities within the computational backbone of the power system that can result in credible, large-scale contingencies, due to common modal failures or coordinated cyber attacks. This may significantly challenge the ability to rebalance the system.

This fundamental difference between probabilistic risk and risk introduced by an intelligent adversary (or adaptive threats) leads to the conclusion that more understanding of the cyber security issues and impacts that are possible on the electric grid is needed. Indeed, there really is no statistical norm for the behavior of cyber attackers and information systems and components failure, and their potential impacts to grid reliability.

Finally, in the computational realm which underlays the cyber framework, multiple types of threats exist that can impact many systems at once. As in business and home computer systems, the common components of computers and digital controls (such as the operating systems, hardware, or even applications) can be exploited. As this computer technology moves further into the operational and control components of the electric grid it is likely that the impacts of an exploit of a common item, be it hardware or application, can quickly outstrip traditional planning criteria designed for actions in the physical realm.

<u>2. Unfamiliarity with unique cyber risk makes it difficult to comprehend</u>

Cyber security presents a unique risk to the reliability of the bulk power system. The cross-cutting nature of technology development and deployment across the electric sector makes this issue key to the entire system, from “smart” meter to generator.

The impacts of poor design or compromise of cyber security may have significant consequences. The lack of clarity makes this risk deceptive and can lead to under consideration as we plan to deal with more complex reliability risks.

<u>3. Lack of reporting and demonstration of incidents and consequences</u>

The universe of reported cyber security incidents, induced failures and near misses is nascent and can lead to underestimating the state of the problem. Specific cyber attack metrics are difficult to collect, analyze and apply. There are several reasons for this lack of important data, these include:

a. Computers and devices can have trouble recognizing a successful attack and/or evidence of the attack can be manipulated by an attacker. This leads many to focus on measurements of successfully prevented attacks, leaving a blind spot with regard to successful attacks.

b. Many system owners are not collecting data or do not have the capability to identify or characterize advanced cyber attacks/incidents

c. Organizations perceive a negative consequence for reporting successful cyber attacks to others.

d. Several cyber incidents affecting power system networks are often discovered after the fact and were not reported in detail.

e. Cyber incidents can occur with such scale that analyzing them in detail can overwhelm resources and techniques/tools are often not capable of providing a complete understanding of the event or identify near misses.

4. Only abstract, naive models of cyber threats exist to identify real concerns

Industrial control systems relied upon for data acquisition, control, telemetry, and protection can be significantly impacted by very simple and in many cases non-directed cyber threats. Accidental cyber-related incidents provide a view of how simple cyber attacks can cause major system consequences. Cyber incidents that inadvertently shut off system processes on a targeted host could result in a lack of necessary situation awareness information or disrupt a relied upon service.

We can collect information on broad cyber attack attempts that demonstrate a significant amount of malicious activity directed at computer systems owned by power system organizations. A survey of 100 information security professionals at U.S. electric companies, conducted by log management firm LogLogic, found that more than half of respondents handle some 150 serious cyber attacks each week and two-thirds responded to at least 75 attempted intrusions per week on corporate systems.[85] The motivation and intent of these attacks are a major factor in why they have not challenged reliability. However, relying on the motivation of a potential adversary should not be the deciding factor on whether there is a challenge.

Any one of these incidents can lead to unintended consequences negatively impacting cyber components relied upon by the power system or they can become the first step in a series of cyber attacks that are designed to disrupt or damage power system components and functions. The hazards are increasingly difficult to manage as system complexity grows, new threats proliferate, and the pace of change accelerates. Cyber risks demand more thorough threat analysis, risk assessment and the ability to rapidly communicate and take action.

5. Cyber threats have disrupted power systems outside of North America

North American systems have not experienced the immediately debilitating, coordinated and sustained cyber attacks witnessed by some Eurasian countries. A strong model of what such an attack might look like on the North American bulk power system, what kind of damage it could cause, and how system integrity could be restored does not presently exist. Security threats affecting the BPS have not been linked to major outages nor represent frequent events and are best defined as historically not being a factor in North America. This is not a true statement for other parts of the world. There have been reports of cyber attacks that have resulted in multiple

[85] http://loglogic.com/resources/white-papers/securing-critical-infrastructure/

city power outages and other impacts to system reliability. These incidents highlight the importance of recognizing this unique risk to reliability and developing appropriate mitigations.

The U.S. and Canadian governments have grown more concerned about the implications of cyber threats to critical infrastructures. This year's annual threat assessment from the Director of National Intelligence (DNI) found that malicious cyber activity grew more sophisticated, targeted and serious during the past year and that trend is expected to continue during the next year. The assessment also stated that the intelligence community expects disruptive cyber activities to be part of future political or military conflicts. The unclassified findings of the assessment were presented by DNI Dennis Blair before the Senate Select Intelligence Committee February 12, 2009.[86]

6. Risk is a co-adaptive process (attacker adapts)

Cyber threats can develop in the shadows and arise in minutes, exhibiting different characteristics than those preceding them. These threats are being driven by intelligent actors attempting to manipulate system components to achieve their objective. Current cyber threats have had overwhelming success against well-defended government networks. The objective of these attackers defines the selection of targets versus the difficulty posed by fielded security measures: the determination of what to attack is a function of the attacker's motivation. If the current motivation leads attackers to compromise government and defense industry systems today, what will they successfully target tomorrow?

The potential for an intelligent cyber attacker to exploit a common vulnerability that affects many assets at once and from a distance is one of the most concerning aspects of this issue. The issue is not unique to the electric sector, but addressing it will require asset owners to apply additional, new thinking on top of sound operating and planning analysis when considering appropriate protections against these threats.

7. System complexity and digital reliance is growing

Over the past 20 years, the industry has become heavily reliant on communications and digital technologies to operate the grid. Until recently, however, relatively few accommodations were made for cyber security requirements needed to protect this infrastructure.

Technology has become an instrumental component that needs to be included in the traditional definition of a power system (generation, transmission, distribution and load). This is especially true since computers and communications are being used to operate the power grid within tighter tolerances (less safety margin). Power system reliability has to account for the following:

a. Reliance upon technologies used in the operation of the power grid are by their very nature, considered complex system because they are real time, distributed and perform operations concurrently.

[86] Annual Threat Assessment of the Intelligence Community for the Senate Select Committee on Intelligence, http://www.dni.gov/testimonies/20090212_testimony.pdf

b. Growing dependency on communications reliability

c. Trend towards centralized processing and control introduces new hazards, such as single points of failure.

d. Component and system security flaws exist and are increasing with the introduction of new technology and applications.

e. Horizontal nature of technology may allow crosscutting impacts to multiple functions or assets. NERC is concerned about weak physical and logical links between organizations and systems (weakest link dilemma).

f. The political and organizational structure of operating entities are often not optimized to account for how to best manage, maintain operational systems, and this is very true for cyber risk management and incident response.

g. The rapid deployment of “smart grid” components, such as “smart meters” and other distribution-level automation controls could potentially open new attack vectors to critical infrastructure components. The reliance of new resources, such as demand response, residential solar, and plug-in hybrid electric vehicles, on these resources creates additional reliability considerations.

Today, in addition to the very real physical risks that must be addressed, layers of complexity in resolving cyber-based risks are only just beginning to be defined and characterized, let alone mitigated. The inescapable trend towards convergence and interconnection of telephony, data, and control system networks has created a complex, non-linear security problem because each of these systems have unique and oftentimes competing security, availability, and performance issues and requirements. When commingled, the performance and security configurations of one directly impacts, and often conflicts with, the performance and security posture of the others.

<u>8. Security constraints exist</u>

Many constraints limit our ability to mitigate cyber risks in industrial control system applications. Some of the constraints have to do with people and the need to provide local and remote access to authorized users to collect information, perform maintenance and trouble shoot problems. Others involve the inherent trust designed into many control system applications, where machines trust other machines, requiring limited authentication to receive control messages. The technologies that we have prioritized for protection are considered by the general information technology market as niche. This limits the amount of security technologies that are optimized to work in these settings.

Cyber Security Summary:

a. Cyber security presents real threats to the Bulk Power System.
b. Risk uncertainty, inadequate reporting, and a lack of experience complicate efforts to mitigate this threat.

NERC Actions

- Monitor and assess cyber risk to the bulk power system through the Critical Infrastructure Protection Committee.
- Work with industry to develop risk mitigation strategies.

Standing Issues

Variable Generation

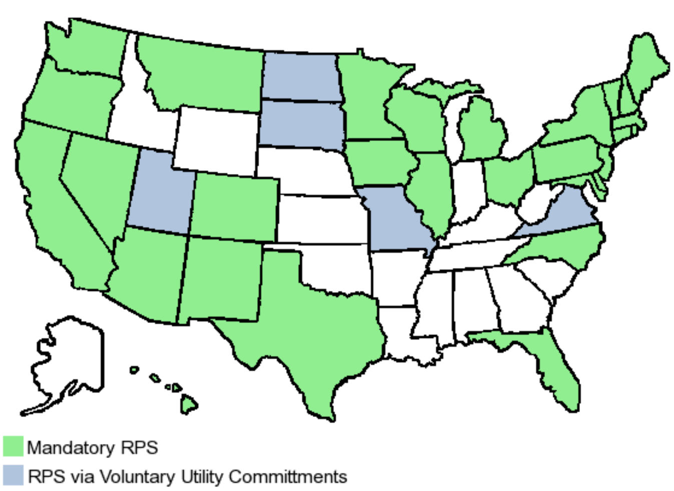
Introduction

As policy and regulations on greenhouse gas emissions, notably CO_2, and mandated Renewable Portfolio Standards (RPS) are being developed by states and provinces throughout North America, the addition of renewable generation into the bulk power system is expected to grow considerably in the near future (See Figure A). The level of commitment to renewables offers benefits such as new generation resources, fuel diversification, and greenhouse gas reductions, and presents significant new challenges that need to be properly addressed to maintain bulk power system reliability. Unlike traditional mostly non-renewable resources, the output of the wind, solar, ocean and some hydro generation resources varies according to the availability of the primary fuel (wind, sunlight and moving water) that cannot be reasonably stored. Therefore, these resources are considered variable, following the availability of their primary fuel source.

There are two overarching attributes of variable generation that can affect the reliability of the bulk power system if not properly addressed:

- **Variability:** The output of variable generation changes according to the availability of the primary fuel resulting in fluctuations in the plant output on all time scales.
- **Uncertainty:** The magnitude and timing of variable generation output is less predictable than for conventional generation.

Figure A: State Renewable Portfolio Standards



Many new variable generation plants interconnecting to the bulk power system will be located in areas remote from the demand centers and existing transmission infrastructure. The *2009 Long-Term Reliability Assessment* estimates that 229,000 MW of wind generation resources (categorized as Future or Conceptual) may be added by the year 2018 in North America.

The National Renewable Energy Laboratory (NREL) estimates that by the year 2025 state Renewable Portfolio Standards (RPS) will result in about 60,000 MW of wind generation infrastructure in the United States typically generating about 180,000 GWh/year (Figure A).[87] The Northwest and Texas are looking at even higher capacity additions than shown on the graph. The

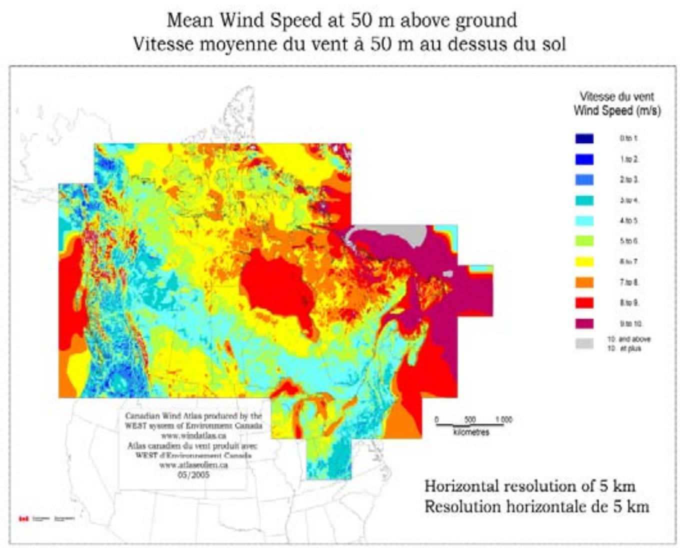
[87] http://www.nrel.gov/wind/systemsintegration/

increasing momentum of initiatives to decrease greenhouse gas (GHG) emissions also creates drivers for the construction of renewable generators, which do not emit GHG, such as wind turbines and solar photovoltaic (PV) cells. Both of these types of generating resources are variable and are susceptible to uncontrolled fuel loss. Therefore, when fuel becomes unavailable, these resources are not dispatchable to grid operators.

Transmission Considerations

In many of the regions in North America that are well suited to wind generation, the resources are remote from existing transmission systems (See Figures B[88] and C[89]), which presents a challenge for integrating wind resources into the bulk power system. Transmission is also critical in delivering the ramping and ancillary services from a large base of generation across a broad geographical/electric Region to keep the supply and demand of electric energy in balance.

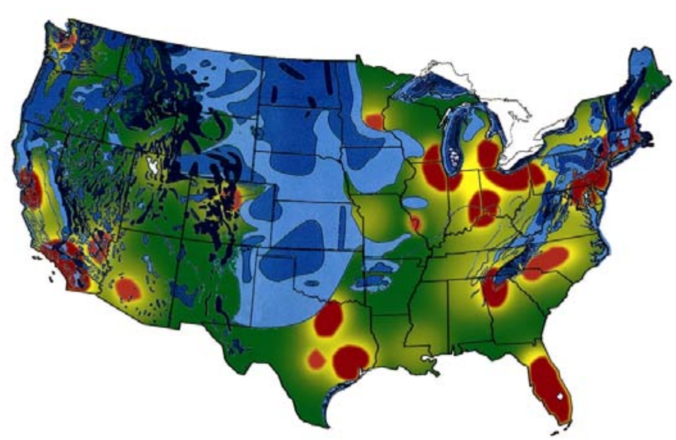
Figure B: Wind Availability in Canada



Additional transmission infrastructure is vital to accommodate large amounts of wind resources in order to:

1. Interconnect variable energy resources planned in remote regions;
2. Smooth the variable generation output across a broad geographical region and resource portfolio; and
3. Deliver ramping capability and ancillary services from inside and outside a Balancing Area to equalize supply and demand.

Figure C: Wind Availability Compared to Demand Centers in the U.S.



Blue - high wind potential,
Brown - large demand centers, and
Green - little wind and smaller demand centers.

System planners and operators increasingly make use of existing transmission assets, in part to allow

[88] http://www.windatlas.ca/en/EU_50m_national.pdf
[89] Source: NREL and EPRI

increased integration of variable generation. High levels of variable generation will require significant transmission additions and reinforcements to maintain bulk power system reliability.[90] State, provincial, and federal government agencies should consider and factor the impact of variable generation integration on inter-state and international bulk power system reliability into their evaluations. These entities are encouraged to work together to remove obstacles, accelerate siting, and approve permits for transmission infrastructure construction and upgrades (See the *Emerging Issue: Transmission Siting* section of this report). Customer education and outreach programs should be fostered to improve the public's understanding of the critical need for transmission, the issues and trade-offs, its role in supporting the overall reliability of the bulk power system, and the need for new transmission infrastructure to support variable generation (renewable) resources.

Transmission planning processes to integrate large amounts of variable generation rely on a number of factors, including:

- Whether government renewable policies or mandates exist;
- Level of variable generation mandated and available variable generation in remote locations;
- Time horizon across which capital investments in variable generation are to be made; and
- Geographic footprint across which the investments occur.

At low variable generation penetration levels, traditional approaches towards sequential expansion of the transmission network and managing wind variability in Balancing Areas may be satisfactory. However, at higher penetration levels, a Regional and multi-objective perspective for transmission planning identifying concentrated variable generation zones, such as those being developed in ERCOT's Competitive Renewable Energy Zone (CREZ) process, California's Renewable Energy Transmission Initiative (RETI) and the Joint Coordinated System Planning Study may be necessary.

Transmission planning and operations techniques, including economic inter-area planning methods, should be used for such inter-area transmission development to provide access to and sharing of resources. Therefore, the composite capacity value of variable generation resources significantly improves when inter-area transmission additions allow variable generators across much wider geographic areas to interact with one another, hence, improving overall system reliability.

As such, the resource adequacy planning process should no longer solely be a function of planning the resource mix alone. Transmission system expansion is also vital to unlock the capacity available from variable generation to serve demand. Further, in those regions with a competitive generation marketplace, regulatory targets such as Renewable Portfolio Standards heavily influence the location and timing of renewable generation investments and their development. Furthermore, government policy and any associated cost allocations (i.e., who pays for transmission, additional ancillary services and ramping capability) will be a key driver for variable generation capacity expansion. Therefore, an iterative approach between

[90] See http://www.20percentwind.org/, and http://www.aeso.ca/downloads/Southern_Alberta_NID_DEC15_POSTED.pdf, for more background.

transmission and generating resource planning is required to cost effectively and reliably integrate all resources.

In summary, transmission expansion, including greater connectivity between balancing areas, and coordination on a broader Regional basis, is a tool that can aggregate variable generators leading to the reduction of overall variability. Sufficient transmission capacity serves to blend and smooth the output of individual variable and conventional generation plants across a broader geographical region. Large Balancing Areas or participation in wider-area balancing management may be needed to enable high levels of variable resources. As long as it is not congested, transmission expansion may not be required to achieve the benefits of larger Balancing Areas or sharing ramping capability and ancillary services between adjacent areas, depending on how existing and planned inter-area transmission assets are used.

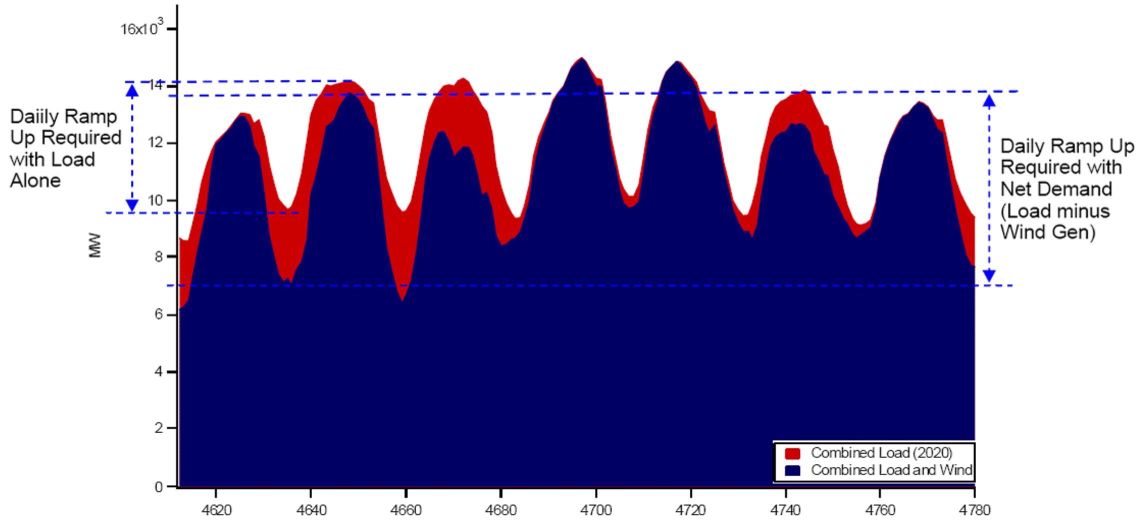
Currently, high voltage transmission overlay expansions are being considered in various parts of the NERC footprint. High voltage alternating current (HVac), high voltage direct current (HVdc) transmission or a hybrid combination of both provides expansion alternatives for this overlay approach. HVac can flexibly interconnect to the existing ac grid, including tapping by generation and load centers, as the grid evolves. However, for very long ground distances (wind sites are hundreds of miles away from demand centers), or for special asynchronous purposes, dedicated HVdc may be a more suitable solution. In addition, to long distances, offshore applications also offer technical challenges that can preclude HVac cables.

Operational Issues

Variable generation resources have a certain amount of inherent uncertainty. However, in many areas where wind power has not reached high penetration levels, uncertainty associated with the wind power has normally been less than that of demand uncertainty. Operating experience has shown that, as the amount of wind power increases beyond 5 percent of installed capacity, there is not a proportional increase in overall uncertainty. Consequently, power system operators have been able to accommodate current levels of wind plant integration and the associated uncertainty with little or no effort.

Forecasting the output of variable generation is critical to bulk power system reliability in order to ensure that adequate resources are available for ancillary services and ramping requirements (See Figure D). The field of wind plant output forecasting has made significant progress in the past 10 years. The progress has been greatest in Europe, which has seen a much more rapid development of wind power than North America. Some Balancing Areas in North America have already implemented advanced forecasting systems, and others are in various stages of implementation including the information gathering and fact-finding stage.

Figure D: Variable Generation can Increase System Flexibility Needs



In the case of wind power, forecasting is one of the key tools needed to increase the operator's awareness of wind plant output uncertainty and assist the operator in managing this uncertainty. Rapid developments are occurring in the field of wind plant output forecasting and its application to effective management of the hour ahead and day-ahead operational planning processes.

Power system operators are familiar with demand forecasting and, while there are similarities, forecasting variable generation output is fundamentally different. The errors in demand forecasting are typically small (in the order of a few percent) and do not change appreciatively over time. On the other hand, wind generation output forecasting is very sensitive to the time horizon and forecast errors grow appreciably with time horizon.

Large unexpected up/down ramps of generation is only one of the challenges associated with integrating high penetrations of variable generation. Other issues, which may also need to be addressed through increased within hourly reserve requirements, include operational uncertainty/lack of visibility and dispatch control of embedded generation, managing minimum load/situations of over-generation, voltage control and frequent Remedial Action Scheme (RAS) arming/disarming. Other potential solutions, some of which have the potential to significantly decrease the total need for within hour balancing reserves, include better forecasting of variable generation, construction of additional transmission infrastructure, control area consolidation, increased dynamic scheduling capabilities, intra-hour scheduling protocols (in the West), ACE diversity sharing, and establishing either organized or bilateral ancillary service markets.

<u>Ancillary Services</u>

Ancillary services are a vital part of balancing supply and demand as part of maintaining bulk power system reliability. Organizations have taken advantage of demand aggregation, provision of ancillary services from other jurisdictions and interconnected system operation for decades. Since each Balancing Area has to compensate for the variability of its own demand and random load variations in individual demands, with enough transmission larger Balancing Areas proportionally require relatively less system balancing through "regulation" and ramping capability than smaller balancing areas. Smaller Balancing Areas can participate in wider-area arrangements for ancillary services to meet NERC's Control Performance Standards (CPS1 and CPS2).

Given that RPS and Green House Gas (GHG) reduction drivers will likely result in the addition of significant quantities of non-dispatchable, variable renewable generation there is a need to plan to reliably integrate this variable generation into the grid. Because balancing authorities (BAs) need to balance loads and generation on a second-by-second basis in order to closely control voltage and frequency on the grid, there is a need for flexible resources, which can respond almost instantaneously to unexpected variations in both load and variable generating resources.

System Flexibility

To ensure sufficient amounts of flexible resources are available to reliably integrate significant levels of variable generation into the grid, resource planners will need to expand their analysis beyond planning Reserve Margins. As resource mixes shift to include high penetrations of variable generation, a resource adequacy metric may be necessary to specifically measure the need for resources to provide ancillary services to meet within hour balancing reserves required to accommodate high levels of wind, solar PV and other variable resources. Although these ancillary services are generally lumped under the heading of regulation reserves, there are actually up to three different time increments to categorize within-hour ancillary services. In many locations, balancing energy transactions are scheduled on an hourly basis. With the advent of variable generation, more frequent and shorter scheduling intervals for energy transactions may assist in the large-scale integration of variable generation. For example, as noted above, Balancing Areas that schedule energy transactions on an hourly basis must have sufficient regulation resources to maintain the schedule for the hour. If the scheduling intervals are reduced for example to 10 minutes, economically dispatchable generators in an adjacent Balancing Area can provide necessary ramping capability through an interconnection.

For example, in WECC these are: 4 second (regulating), 10 minute (following) and/or hourly. Not all resources have the ability to ramp up and down quickly enough to provide ancillary services, especially in the 4 second and 10 minute timeframes. Only flexible resources such as conventional hydro generation, combustion turbines and perhaps other gas-fired plants, certain types of Demand Response and storage technologies, including pump-storage, have these necessary rapid ramping attributes.

Within a Balancing Area, as the level of variable generation increases, the variability when coupled with extreme events may not be manageable with the existing conventional generation resources within the Balancing Area alone. Furthermore, base load generation might have to be heavily cycled for the local generation to follow the sum of load and variable generation variations, posing reliability concerns as well as economic consequences. If there is sufficient bulk power transmission, this situation can be managed by obtaining ancillary services and flexible resources from a larger generation base, such as by participation in wider-area balancing management or through Balancing Area consolidation. With sufficient bulk power transmission, larger Balancing Areas or participating in wide-area arrangements, can offer reliability and economic benefits when integrating large amounts of variable generation. In addition, transmission can lead to increased diversity of variable generation resources and provide greater access to more dispatchable resources, increasing the power systems ability to accommodate larger amounts of variable generation without the addition of new sources of system flexibility. Balancing Areas should evaluate the reliability and economic issues and opportunities resulting from consolidation or participating in wider-area arrangements such as ACE sharing (e.g., WECC's ACE Diversity Interchange[91]) or wide area energy management systems.

Therefore, resource planning processes should be adjusted to ensure that the designed system would include resources that provide the desired flexibility. From a planning perspective, the question is "how does one ensure that adequate generation reserve, demand side resources or transmission transfer capability to neighboring regions is available to serve demand and maintain reliability during the expected range of operating conditions including severe variable ramping conditions in a Balancing Area?" If the underlying fuel is available, new variable generation technologies can readily contribute to the power system ancillary services and ramping needs. Upward ramping and regulation needs, beyond the maximum generation afforded by availability of the primary fuel (wind or sun), are important planning considerations. Unless these newer technologies are designed to provide inertial response, the planner must ensure other sources of inertia are available to meet bulk power system reliability requirements under contingency conditions.

A comprehensive variable generation integration study should be conducted assessing the appropriate level of system flexibility to deal with system ramping and reserve needs. There are many different sources of system flexibility including; 1) ramping of the variable generation (modern wind plants can limit up- and down-ramps), 2) regulating and contingency reserves, 3) reactive power reserves, 4) quick start capability, 5) low minimum generating levels and 6) the ability to frequently cycle the resources' output. Additional sources of system flexibility include the operation of structured markets, shorter scheduling intervals, demand-side management, reservoir hydro systems, gas storage and energy storage. System planners must ensure that suitable system flexibility is included into future designs of the bulk power system, as this system flexibility is needed to deal with, among many conditions, the additional variability and uncertainty introduced into power system operations by large-scale integration of variable generation. This increased variability and uncertainty occurs on all time scales, particularly in the longer timeframes, (i.e., ramping needs).

Many areas also consider the overall system load factor as an indicator of the amount of flexible generation required to operate between minimum daily demand and peak daily demand. For example, in a region with a very high load factor like Alberta that has an annual load factor in excess of 80 percent, the generation resource mix may have developed with a large amount of baseload generation and will inherently have a lesser amount of dispatchable or flexible generation available to balance variable generation resources. Under these circumstances, a large penetration of variable generation would require the addition of added flexible resources or access to additional resources (via interconnections) and requirements for increased flexible performance including from variable resources themselves. Wind plant integration requirements are not generic and will be affected by the circumstances and characteristics of each area (i.e., interconnection capability, load factor, system resource mix, etc.).

[91] See http://www.wecc.biz/index.php?module=pnForum&func=viewtopic&topic=909

Location and flexibility of resources is critical in the future design of the system. As resources become more distributed, control and storage equipment (e.g., STATCOMs, storage devices, SVCs) may also be distributed. In this respect, it may be necessary to relocate control and storage equipment to maintain proper function of the system as new resources connect. Wind plant aggregation across broad geographical regions can also significantly reduce output variability, decrease uncertainty and, consequently, reduce the need for additional flexibility.

Therefore, integration studies need to be conducted to assess the appropriate level of system ramping capabilities (intra-hour and load following), reserves, minimum demand levels, rapid start capability, scheduling intervals, additional transmission and system inertial response. The individual characteristics of each system (i.e., generation resource mix, ramping capability, amount of dispatchable resources, etc.) will affect these impacts. High quality, high resolution (typically sub-hourly) variable generation and load data is required to ensure the validity of the study results.

NERC's Integration of Variable Generation Task Force

Background

Anticipating the growth of variable generation, in December 2007, the North American Electric Reliability Corporation's (NERC) Planning and Operating Committees created the Integration of Variable Generation Task Force (IVGTF), charging it with preparing a report to identify; 1) technical considerations for integrating variable resources into the bulk power system, and 2) specific actions, practices and requirements, including enhancements to existing or development of new reliability standards.

The IVGTF delivered its final report for Phase I, which was approved by NERC's Board of Trustees.[92] Within this report was a three-year work plan along with a series of industry recommendations.

Status

The IVGTF has kicked-off Phase II of their work. A Leadership Team meeting was held and the work plan was detailed. The leadership team will organize sub-groups focused on the delivery of the reports and NERC Standard evaluations. Liaison activities have been organized with both NERC (Resource Issues Subcommittee) and external organizations (IEEE and CIGRE).

Following is a summary of the consolidated conclusions, recommended actions and observations developed by the IVGTF:

1. **Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term bulk power system reliability**

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

1.1. Standard, valid, generic, non-confidential, and public power flow and stability models (variable generation) are needed and must be developed, enabling planners to maintain bulk power system reliability.
1.2. Consistent and accurate methods are needed to calculate capacity values attributable to variable generation.
1.3. Interconnection procedures and standards should be enhanced to address voltage and frequency ride-through, reactive and real power control, frequency and inertial response and must be applied in a consistent manner to all generation technologies.
1.4. Resource adequacy and transmission planning approaches must consider needed system flexibility to accommodate the characteristics of variable resources as part of bulk power system design.
1.5. Integration of large amounts of plug-in hybrid electric vehicles, storage and Demand Response programs may provide additional resource flexibility and influence bulk power system reliability and should be considered in planning studies.
1.6. Probabilistic planning techniques and approaches are needed to ensure that system designs maintain bulk power system reliability.
1.7. Existing bulk power system voltage ride-through performance requirements and distribution system anti-islanding voltage dropout requirements of IEEE Standard 1547 must be reconciled.
1.8. Variable distributed resources can have a significant impact on system operation and must be considered and included in power system planning studies.

2. Operators will require new tools and practices, including enhanced NERC Standards to maintain bulk power system reliability

2.1. Forecasting techniques must be incorporated into day-to-day operational planning and real-time operations routines/practices including unit commitment and dispatch.
2.2. Balancing Areas must have sufficient communications for monitoring and sending dispatch instructions to variable resources.
2.3. Impact of securing ancillary services through larger balancing areas or participation in wider-area balancing management on bulk power system reliability must be investigated.
2.4. Operating practices, procedures and tools will need to be enhanced and modified.

3. Planners and operators would benefit from a reference manual which describes the changes required to plan and operate the bulk power and distribution systems to accommodate large amounts of variable generation

3.1. NERC should prepare a reference manual to educate bulk power and distribution system planners and operators on reliable integration of large amounts of variable generation.

Greenhouse Gas Legislation

Federal, state, and provincial CO_2 legislation continues to be pending throughout North America. In the United States, a number of additional Regional and state activities have resulted in a variety of renewable portfolio standards. NERC's Planning Committee has created the Reliability Impacts of Climate Change Initiatives Task Force (RICCITF) to review CO_2 legislative and regulatory impacts on bulk power system reliability.[93] Further, NERC staff prepared a report documenting industry concerns and reliability considerations.[94]

Taken individually, state, provincial, and Regional initiatives may not significantly affect bulk power system reliability. However, as more and more state, provincial, and Regional initiatives begin to take effect and federal climate change initiatives are considered in the U.S., there is an increasing need to review the collective impact of these initiatives on the bulk power system and identify effective means to help the electric industry meet these climate change initiatives without degrading system reliability.

These climate change initiatives include:

- **State and Provincial Renewable Portfolio Standards:** Renewable Portfolio Standards typically require load-serving entities in a given state to acquire a certain percentage of their energy supply from renewable resources by a target year (for example: 20 percent by 2020). Twenty-nine U.S. states and three Canadian provinces have some kind of renewable portfolio standard in place. NERC has studied the reliability consideration resulting from accommodating high levels of variable renewable resources (See *Standing Issue: Variable Generation* section).[95]
- **Other State and Provincial Climate Goals:** All remaining Canadian provinces and six U.S. states have some form of policy in place to address climate change and greenhouse gas emissions, either through specific MW goals for electric generation or other means.
- **Regional Initiatives:** Initiatives such as the Regional Greenhouse Gas Initiative in the Northeast (RGGI) and Western Climate Initiative (WCI) have created multi-state and cross-border partnerships to reduce greenhouse gas emissions on a Regional basis.
- **U.S. Federal Climate Change Legislation:** The U.S. Senate and House of Representatives are considering various legislative proposals to reduce carbon dioxide (CO_2) emissions, including a federal RPS and a federal Cap and Trade program.

As states/provinces begin adopting a variety of approaches to greenhouse gas emission regulation, the prospect grows for federal regulation. Further, in the United States, an April 2007 United States Supreme Court decision[96] determined greenhouse gas regulation could fall under the purview of the U.S. Environmental Protection Agency (EPA).

93 http://www.nerc.com/filez/riccitf.html
94 http://www.nerc.com/files/2008-Climate-Initiatives-Report.pdf
95 http://www.nerc.com/files/IVGTF_Report_041609.pdf
96 http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf

Reliability Considerations

Some of these programs may conflict with bulk power system reliability objectives. For example, a Green House Gas (GHG) Cap and Trade system with too few carbon allowances could result in the inability to dispatch generation resources needed for reliability. Key reliability considerations include the following:

- ***Implementation*** of the targeted levels of greenhouse gas reductions resulting from the initiatives must have reasonable targets and timelines. Deployment of carbon reduction strategies through either Cap and Trade or Carbon tax must recognize its potential impact on bulk power system reliability. Further, legislation timing must match technology development and the ability of the retail providers to implement.
- ***Generation*** options are reduced, as capacity mix for the future energy outlook could significantly change, including the issues of integrating large amounts of wind plants. Proposals that make emitting generators the point of regulation ignore the fact that generators are typically not also retail providers and therefore are not in a position to influence decisions about investments in alternative, lower-emitting resources. Neither are they able to implement customer-focused energy efficiency or Demand Response programs. When independent generators or wholesale generators that are forced to comply do not have viable alternatives other than shutting down generation or losing money, they may stop generating
- ***Transmission*** will be vital to reliably integrate and operate the bulk power system to meet demand growth, renewable portfolio standards and replace supply due to early unit retirements. Changing the resource mix will have a significant impact on transmission requirements. Challenges also exist in the construction and siting of needed infrastructure.
- ***Demand-side*** options can play a significant role in reducing CO_2 emissions. However, there are few bulk power system reliability concerns about integration of Demand-Side Management, which includes energy efficiency and Demand Response.

Separate mandates for carbon reduction, development of renewable resources and energy efficiency may create redundant, inconsistent and/or conflicting requirements for utilities. This is resulting in greater uncertainty of supply to industrial, commercial and residential customers.

The current stand-alone Renewable Portfolio Standards, when combined with GHG cap-and-trade programs with generators as the point of regulation can add to uncertainty in the long-term. Industry faces increased uncertainty in the availability of long-term base-load energy resources due to greenhouse gas regulations at the same time they are being required to add new, in many cases variable, renewable resources in increasing percentages.

Status of RICCI Task Force

NERC’s Planning Committee (PC) recognized the potential impacts and continental scope of Climate Change legislation, and as many of the variables impact reliability on a NERC-wide scale. Therefore, the PC organized the Reliability Impacts of Climate Change Initiatives Task Force (RICCI TF). The goal of this effort is to assess the reliability considerations of climate change initiatives and the technologies promulgated by them, ranging from large-scale integration of Smart Grid to nuclear generation to energy storage. For example, large-scale integration of solar and wind energy creates new planning and operating challenges.

Phase I of this effort is focusing on providing a report with a high-level view of reliability considerations for Climate Change issues and will identify and categorize technical reliability considerations. If required, a Phase II effort will commence providing a technical assessment of North America, building on the results from the Phase I report, performing reliability assessments of the bulk power system for selected scenarios. Initially, a resource assessment will be performed, and then identification of potential bulk power system reliability issues and requirements.

Reactive Power

Reactive energy cannot be transmitted as far as real energy. This is primarily due to the physical attributes of transmission lines. As a result, there is the need for reactive energy to be supplied by local reactive energy sources to meet customer reactive energy demand plus system reactive losses. Reactive losses on heavily loaded transmission lines often exceed the local static reactive energy produced by the transmission lines. When sufficient local reactive energy sources are not provided, large voltage drops will occur. Transmitting MVar across a transmission line produces voltage drops in the range of 5 to 25 times higher than transmitting an equal amount of MW. Generators, static var compensators (SVCs), static compensators (STATCOMs), other Flexible AC Transmission Systems (FACTS) and synchronous condensers provide dynamic reactive power (See Figure Power 1).

Figure Power 1: An SVC.[97]

Generation is becoming more remote from load due to increased use of renewable generation and transmission system expansion enabling increased economic transfers. This directly leads to changes in the need for reactive power and voltage support. Market-driven dispatch or increased reliance on remote renewable generation sources can create significantly different flow patterns on the transmission network, with a significant impact on var needs

Static capacitors, under substation low voltage conditions, used in devices such as SVCs do not produce maximum reactive power as reliably as dynamic self-excited power equipment. This is because capacitor reactive power output depends on substation voltage. Capacitor reactive power output changes in proportion to the square of voltage magnitude. For example if substation voltage declines from 100 percent to 90 percent of nominal voltage, static reactive power output declines from 100 percent of capability to 81 percent. Dynamic reactive resources are typically used to adapt to rapidly changing conditions on the transmission system, such as sudden loss of generators or transmission facilities. In contrast, switched static devices are typically used to

[97] http://www.amsc.com/products/transmissiongrid/static-VAR-compensators-SVC.html

adapt to slowly changing system conditions. Generators have differing abilities to provide var depending on a number of factors such as; stator ampere rating, exciter system dc field current rating, AC terminal high voltage limit, actual MW output of the prime mover compared to generator rated power factor original design, control system variations, equipment changes due to age, etc. An appropriate combination of both static and dynamic resources is needed to ensure reliable operation of the transmission system.

Switched devices are typically used to adapt to slowly changing system conditions such as daily and seasonal load cycles and changes to scheduled transactions. Static capacitor resources typically have lower capital cost than dynamic devices, and from a systems point of view, static capacitors are used to provide normal or intact-system voltage support. Often it is possible to locate static capacitors near reactive load, increasing their effectiveness. By contrast, dynamic reactive resources are used to adapt to rapidly changing conditions on the transmission system, such as sudden loss of generators or transmission facilities. Coordination is necessary to provide the appropriate mixture of local automatic control.

The NERC Transmission Issues Subcommittee (TIS) has developed a Reactive Control and Support Whitepaper which provides additional information on this topic.[98]

Smart Grid and Advanced Metering Infrastructure

The U.S. Energy Independence and Security Act[99] of 2007 articulates many Smart Grid Functions and the July 2009 FERC Policy Statement – Smart Grid Policy[100] clarifies that it includes two crosscutting issues:

1. Cyber security and physical security to protect equipment that can provide access to Smart Grid operations; and

2. A common information framework with four key grid functionalities:
    i. Wide-area situational awareness;
    ii. Demand response;
    iii. Electric storage; and
    iv. Electric transportation.

Proposed legislation in Canada reflects similar attributes for Smart Grid.[101] Roughly, this can be summarized as a reliable electric power system, from generation source to end-user that integrates advanced sensing and communications with real-time monitoring to enable the two-way flow of energy and new forms of supply, delivery, and use.

---

98 http://www.nerc.com/docs/pc/tis/Reactive%20Support%20and%20Control%20Whitepaper%20&%20SAR.zip

99 http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f: h6enr.txt.pdf – see TITLE XIII—SMART GRID.

100 http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-3.pdf

101 For instance, proposed "Bill 150, Green Energy and Green Economy Act, 2009" states, "the smart grid means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems" at http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=2145.

Many aspects, though not all, of Smart Grid functions will occur at the distribution level. The electrification of the transportation industry, increase of time-of-use pricing, and growth of Demand Response programs will considerably alter the dynamics of future electric power use. In aggregate, these distribution level functions can have significant impacts on the bulk power system reliability. These changes can alter the nature of demand and will require coordinated, interoperable control systems to function reliably. Examples of emerging Smart Grid technologies include distributed automation, advanced metering infrastructure (AMI), advanced sensing and monitoring, distributed energy resources and improved communications devices. Adequacy and operational reliability of the system must be maintained during the development, implementation, and operation phases of all new technology.

Regulatory changes and economic incentives are driving change in the development and integration of Smart Grid technologies. Government and industry organizations are moving quickly to develop standards and implement new devices and functions to the system. Many of these initiatives will gain momentum and become widespread as interoperability standards become accepted and financial opportunities become clear. Further, Smart Grid may facilitate the integration of renewable resources, reduce energy use, deploy Demand Response, and reduce greenhouse gases.[102]

Renewable resources that may be far away from demand centers will increasingly provide the fuel for electricity. This will require a robust transmission system and a sophisticated marketplace—further enhanced by a Smart Grid—to accommodate an unprecedented amount of variability and uncertainty. Regardless of these challenges, the Smart Grid must ensure the system maintains voltage and frequency control.

Depending on the penetration and integration levels of Smart Grid technologies, the benefits and challenges to reliability can be considerable. For instance, improvements in communications and the use of "smart" devices could improve grid reliability by improving and broadening the use of Demand Response and providing more information about the status of the grid components. Conversely, ineffective or uncoordinated control systems for new devices could hinder reliability.

Smart Grid technologies (devices and communications platforms) may enable distributed resources to be integrated into the grid cost effectively, efficiently, and reliably. However, the types and mix of these resources should consider interconnection requirements to ensure reliability of the bulk power system. The ability of generation sources, grid infrastructure, and end-use devices to sense and communicate is a radical development with profound benefits and challenges. Ultimately, the marketplace will decide which communications platforms and security architectures will be successful, but a collaborative effort between government, standards, end-user, and industry groups will need to carefully steer the process from theory to practice to common practice—much like the story of cellular telephones that went from an expensive rarity to common use.

[102] http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-3.pdf

The integration of Smart Grid must be done wisely to ensure that the reliability benefits are realized, rather than compromised. Advanced diagnostics on the bulk power system can provide more information and control. Near instantaneous monitoring and power flow control technologies will provide the system with the tools necessary to improve reliability and security. Siting Smart Grid technologies on existing transmission systems can increase the available capacity and increase stability margins yet provide new opportunities for cyber security vulnerabilities.

Properly controlled Smart Grid devices—and the coordinated systems of systems that they will require to function—can benefit the grid by shaping demand, improving communications, and providing better operational awareness. Conversely, an *ad hoc* adoption of new technologies could result in incompatible and poorly coordinated control systems, unreliable devices, and cyber security gaps that could be detrimental to system reliability. The interconnected nature of the system improves its stability and its ability to recover from contingencies while increasing cyber security risks as the system embraces and begins to rely on more automation, connectivity, and digital devices. Going forward, the system will require upgradable and interoperable architectures and elements that allow the best technologies to be seamlessly integrated without threatening reliability.

Political and economic momentum (regarding Smart Grid specifically, but in general as the economy recovers from the recession) will continue to drive development and integration of Smart Grid technologies over the next one to five years. These developments may begin to have an aggregated impact on the bulk power system in six to ten years.

Future studies could identify how to reliably integrate Smart Grid technologies and explore improved models that address the interaction of controls and protection characteristics, power quality, and frequency response related to the integration of new Smart Grid devices.

NERC's Smart Grid Task Force

NERC's Planning Committee (PC) recognized the potential impacts of Smart Grid and organized the Smart Grid Task Force (SGTF) in July 2009. The goal of this effort is to identify any issues and/or concerns of the Smart Grid with respect to bulk power system reliability.[103] The SGTF will also determine the cyber-security and critical infrastructure protection implications of Smart Grid technologies.

[103] http://www.nerc.com/docs/pc/sgtf/SGTF_Scope_07-29-09final.pdf

Regional Reliability Assessment Highlights

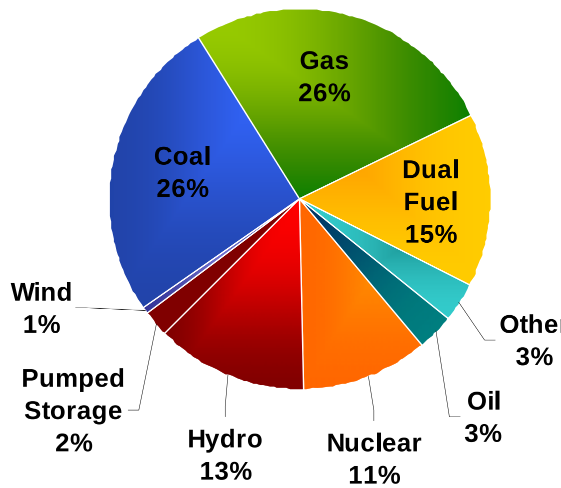
Regional Resource and Demand Projections

The figures in the Regional self-assessment pages show the Regional historical demand, projected demand growth, Reserve Margin projections, and generation expansion projections reported by each Region. Highlights are arranged by interconnection and provide information on Regions and subregions (Figures 2, 3).

Capacity Fuel Mix

The Regional capacity fuel mix charts show each Region's relative reliance on specific fuels[104] for its reported generating capacity (See Figure 1). 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 Highlights 1: 2009 NERC Relative Capacity by Fuel Mix



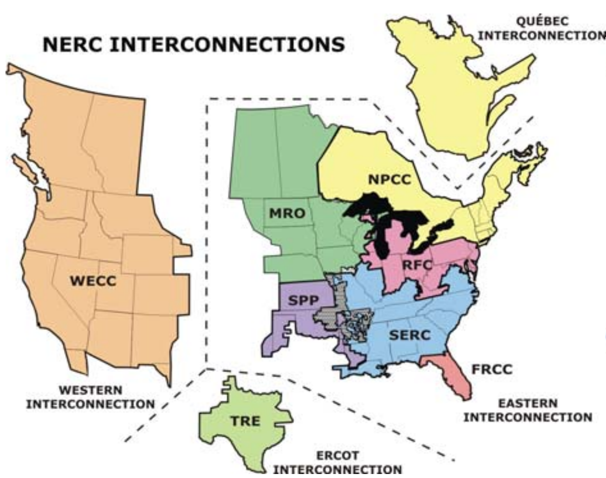


Figure 2: NERC Interconnections.

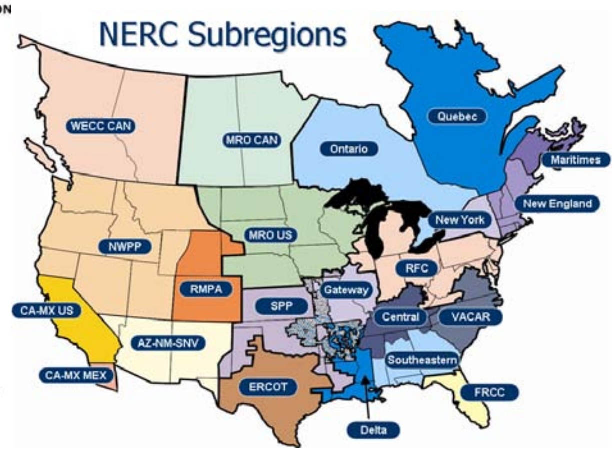


Figure 3: NERC Subregions.

[104] 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.

Texas Interconnection Highlights

ERCOT Highlights

This year's long-term assessment for resource adequacy in the ERCOT Region has improved over last year's outlook. The annual Reserve Margin for the Region does not drop below the minimum target level of 12.5 percent until 2016, due to additional generating units that have gone into service or have signed interconnection agreements and a lower expectation of load growth in the early years of the assessment due to the current economic recession. There are significant amounts of additional generation being considered for addition in the Region, but have not yet been developed to the point of meeting the criteria for inclusion in this Reserve Margin calculation.

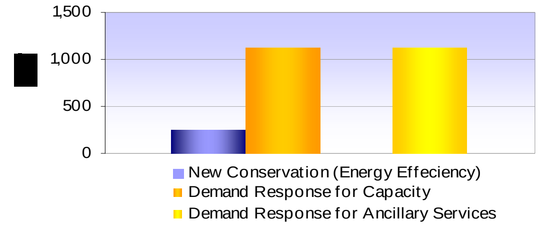
The number of planned transmission circuit miles and autotransformer additions over the first five years has increased since last year's long-term assessment, primarily due to the inclusion of the new lines that have been ordered by the Public Utility Commission of Texas to complete its Competitive Renewable Energy Zones (CREZs). The increase in wind generation is expected to result in congestion on multiple constraints until the new CREZ transmission lines are added between West Texas and the rest of the ERCOT system. From an operational perspective, the increasing reliance on wind generation is expected to increase operating challenges. Several initiatives have been undertaken, and others continue to be under development, to ensure the appropriate procedures and requirements are in place to meet these challenges.

ERCOT

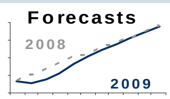
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	63,491	76,134
Direct Control Load Management	0	0
Contractually Interruptible (Curtailable)	0	0
Critical Peak-Pricing with Control	0	0
Load as a Capacity Resource	1,115	1,115
Net Internal Demand (MW)	62,376	75,019

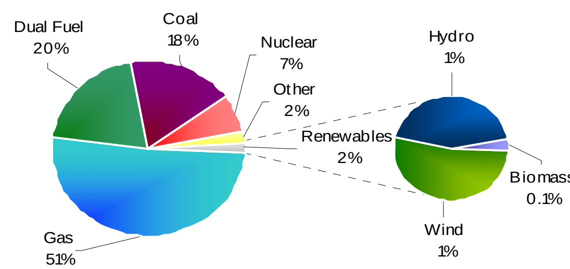
Demand-Side Management - 2018



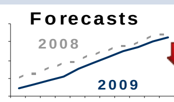
Energy Consumption	2009	2017
Net Energy to Load (GWh)	312,401	369,590
Percentage Change from 2008 Forecast	-2.2%	0.2%



Relative Capacity Mix by Fuel Type - 2009



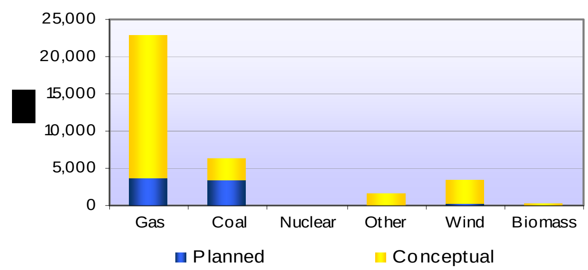
Peak Demand Comparison	2009	2017
2008 Demand Forecast	66,087	76,260
Percentage Change from 2008 Forecast	-3.9%	1.8%



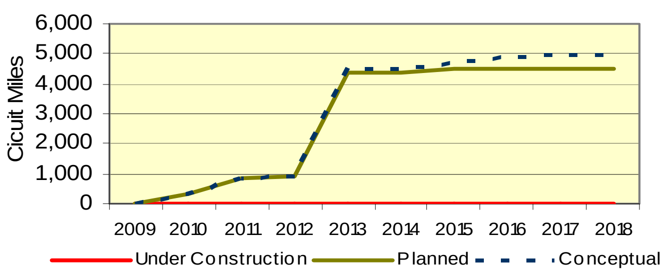
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	72,204	15.8%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	79,525	6.0%
Prospective Capacity Resources	79,525	6.0%
Adjusted Potential Capacity Resources	84,969	13.3%
Total Potential Capacity Resources	106,745	42.3%
NERC Reference Margin Level	-	12.5%

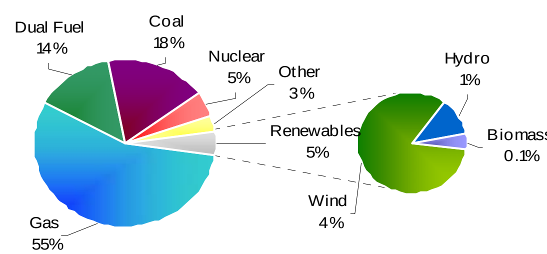
Projected On-Peak Fuel-Mix 10 Year Change



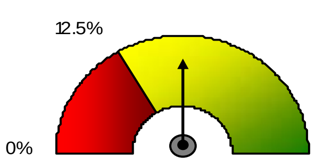
Projected Transmission Additions



Relative Capacity Mix by Fuel Type - 2018

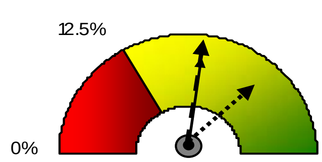


2009 Reserve Margin



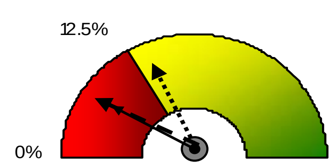
Existing-Certain & Net Firm Transactions

2013 Reserve Margins



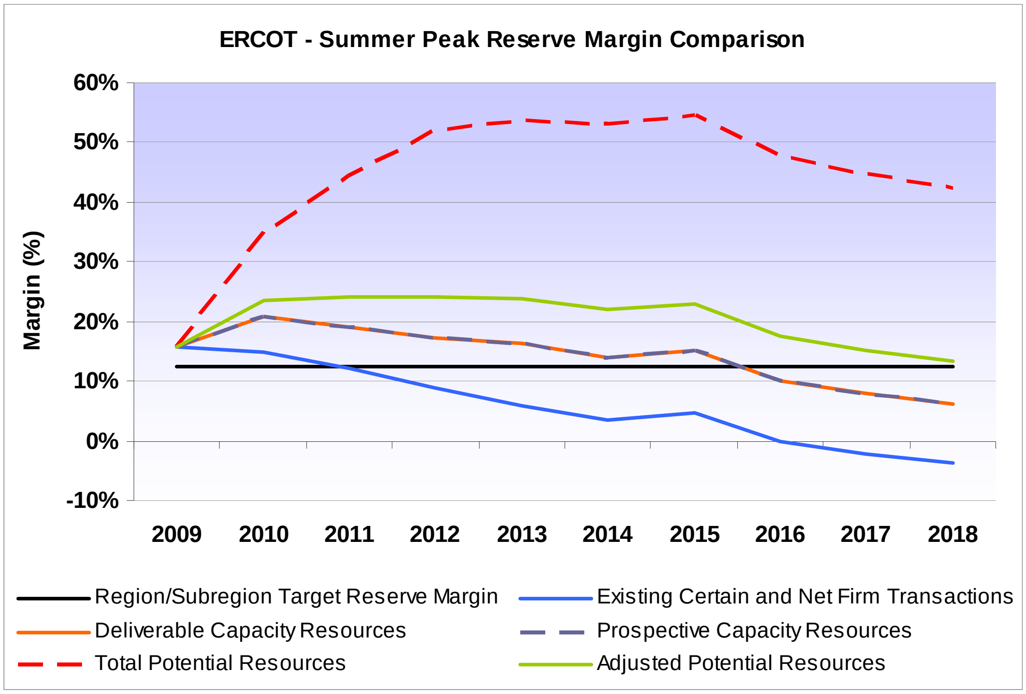
Deliverable
Prospective
Adjusted Potential

2018 Reserve Margins

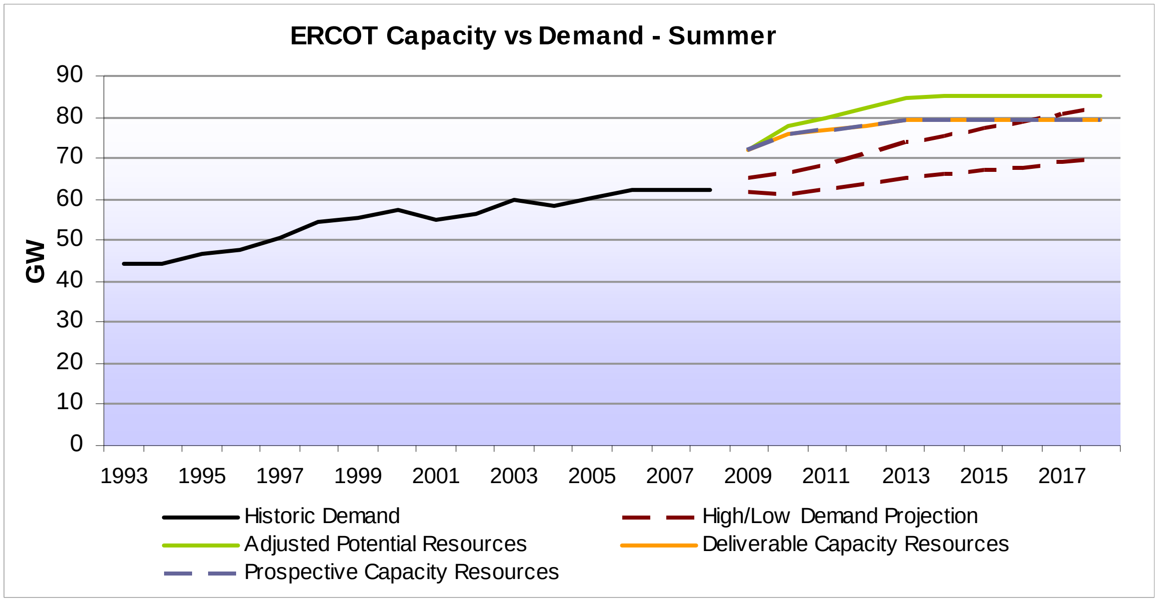


Deliverable
Prospective
Adjusted Potential

For the 2009 to 2018 assessment period, ERCOT Reserve Margins are projected to fall below the NERC Reference Margin Level by 2011 if no new resources are added. Even with the addition of all Future Resources, a drop below the NERC Reference Margin Level is projected by 2016. ERCOT may need additional resources to meet the NERC Reference Margin Level.



For the high demand projection,[105] ERCOT capacity resources appear sufficient during the assessment period when considering Adjusted Potential Resources. However, Deliverable and Prospective Capacity Resources are lower than the high demand projection by 2016.



[105] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

Western Interconnection Highlights

WECC Highlights

WECC loads are growing, at a lower rate than reported in 2008 — the projected 2009 summer total internal demand of 160,688 MW is expected to increase by 1.8 percent per year to 188,030 MW in 2018.

The planning Reserve Margins used for this report were developed using a building block method. The planning Reserve Margins will be referred to as target margins in this assessment. These target margins range between 10.1 and 22.3 percent, with an average of 17.2 percent in summer and 16.1 percent in winter.

Reserve margins in all of WECC's subregions have improved due to decreased load growth, adverse economic conditions, increased generation capacities, and demand-side-management programs.

Using the NERC definitions of future resources, WECC assumes that all of the Future Planned[106] (FP) resources will be constructed and that both the potential, Future Other (FO), and Conceptual resource additions should be adjusted by confidence factors to determine the expected adjusted potential resource additions. The contribution toward the summer peak from the Existing Certain (EC), FP, FO, and Conceptual resources are summarized in the following table:

*Existing Resources	Future Planned Resources	Potential Future Other Resources	Potential Conceptual Resources	*Adjusted Future Other Resources	*Adjusted Conceptual Resources
**201,002	37,708	53	13,196	0	7,772
197,568	37,708	Potential = 13,249 MW		Adj. Potential = 7,772 MW	
* The 2018 confidence factors for the Region were 0 and 59 percent for the FO and Conceptual resources. ** Value for July 2009 and includes 3,434 MW that is scheduled for maintenance.					

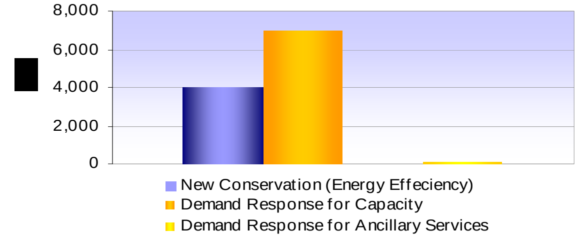
WECC is comprised of four general subregions: the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA), the Arizona–New Mexico–Southern Nevada area (AZ-NM-SN), and the California–Mexico area (CAMX). The NWPP subregion includes portions of the U.S. (NWUS) and Canada (NWCN). The CAMX subregion includes portions of the U.S. (CMUS) and Mexico (CMMX).

[106] NERC definition – See appendix III Capacity and Demand Definitions

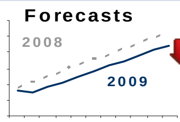
WECC
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	160,688	188,030
Direct Control Load Management	1,433	2,127
Contractually Interruptible (Curtailable)	2,137	2,465
Critical Peak-Pricing with Control	5	48
Load as a Capacity Resource	715	2,310
Net Internal Demand (MW)	156,398	181,080

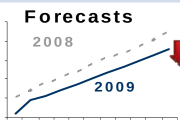
Demand-Side Management - 2018



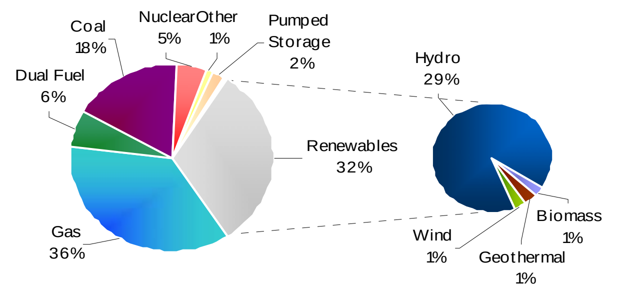
Energy Consumption	2009	2017
Net Energy to Load (GWh)	874,773	1,006,102
Percentage Change from 2008 Forecast	-3.1%	-3.7%



Peak Demand Comparison	2009	2017
2008 Demand Forecast	163,741	190,150
Percentage Change from 2008 Forecast	-1.9%	-4.0%



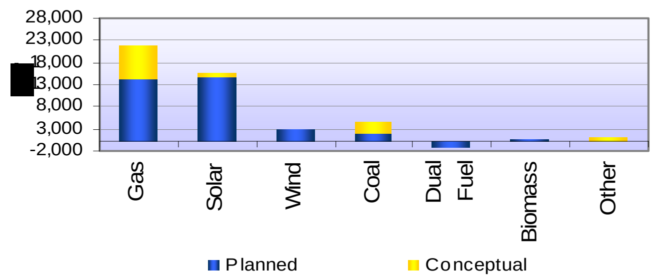
Relative Capacity Mix by Fuel Type - 2009



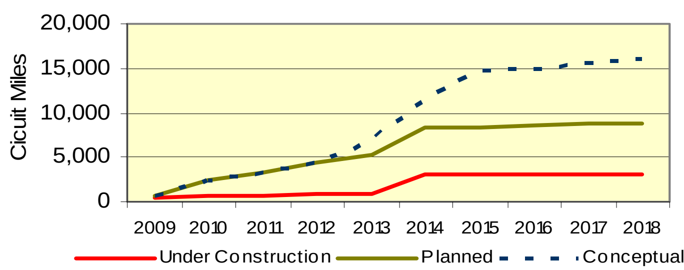
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	197,568	26.3%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	234,561	29.5%
Prospective Capacity Resources	234,561	29.5%
Adjusted Potential Capacity Resources	242,333	33.8%
Total Potential Capacity Resources	247,810	36.9%
NERC Reference Margin Level	-	17.9%

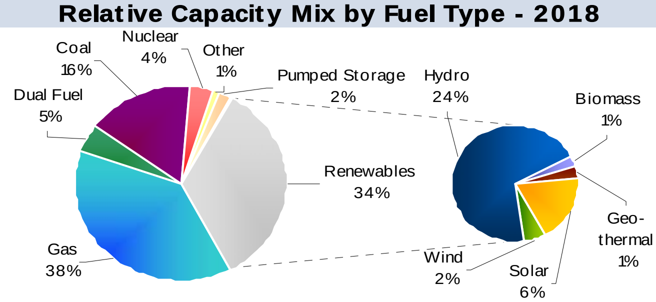
Projected On-Peak Fuel-Mix 10 Year Change



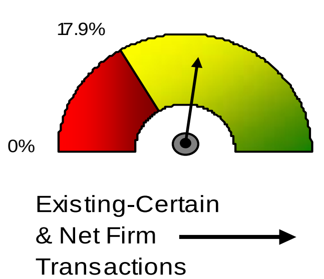
Projected Transmission Additions



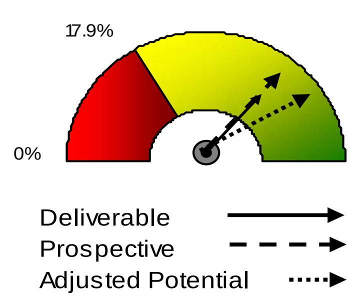
Relative Capacity Mix by Fuel Type - 2018



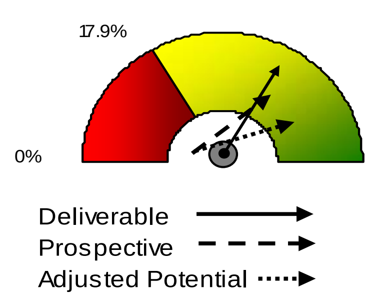
2009 Reserve Margin



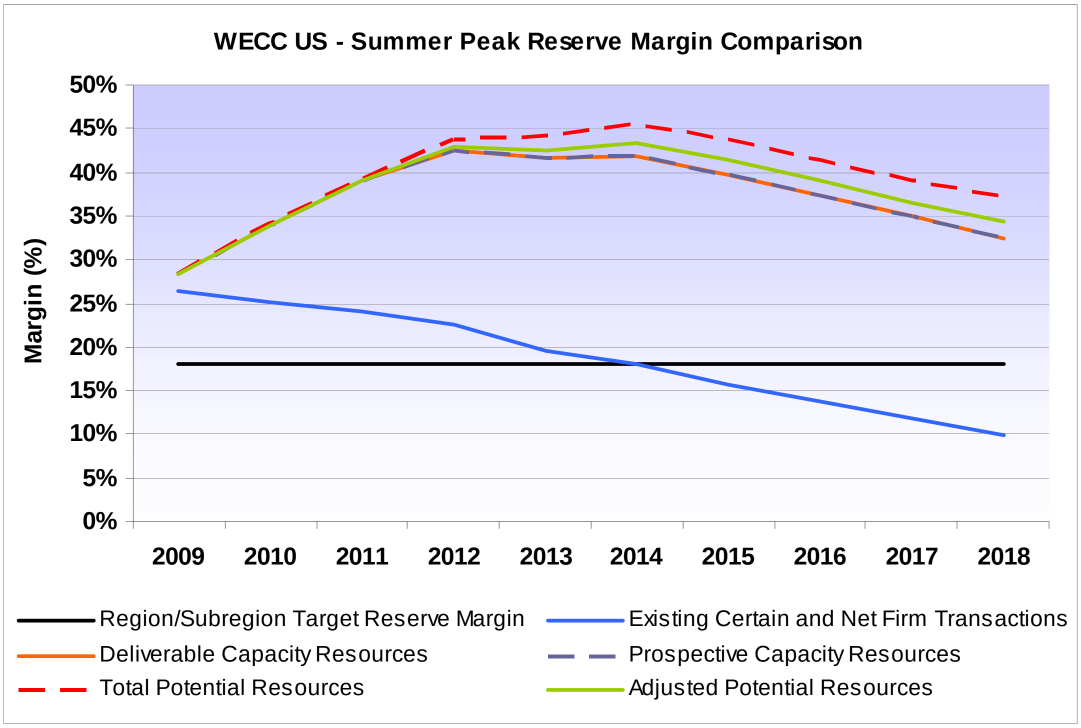
2013 Reserve Margins



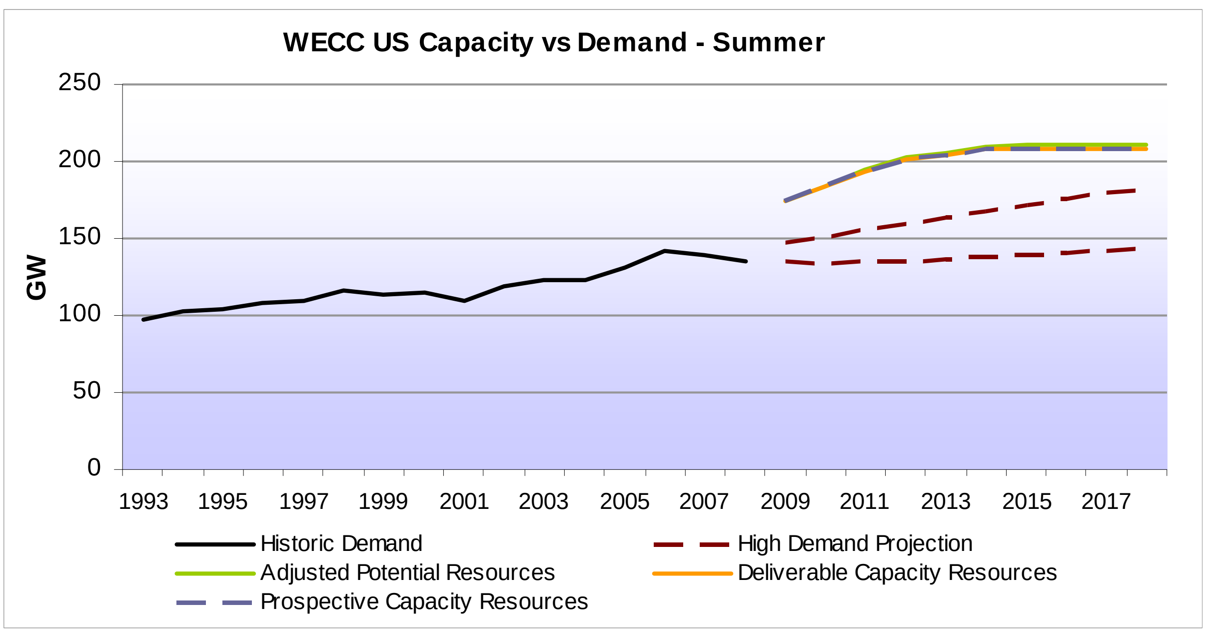
2018 Reserve Margins



For the 2009 to 2018 assessment period, WECC-US Reserve Margins are expected to fall below the NERC Reference Margin Level by 2015 if no new resources are added. With the addition of Future Resources, WECC-US Reserve Margins should remain higher than the NERC Reference Margin Level.

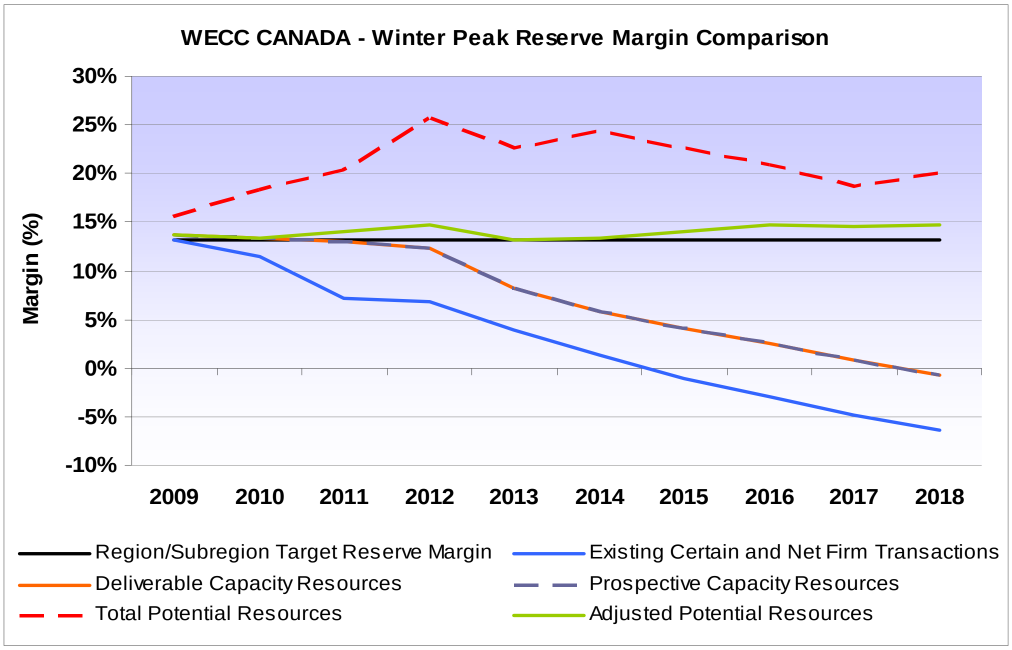


For the high demand projection[107], WECC-US capacity resources appear sufficient during the assessment period when considering all categories of projected capacity resources.

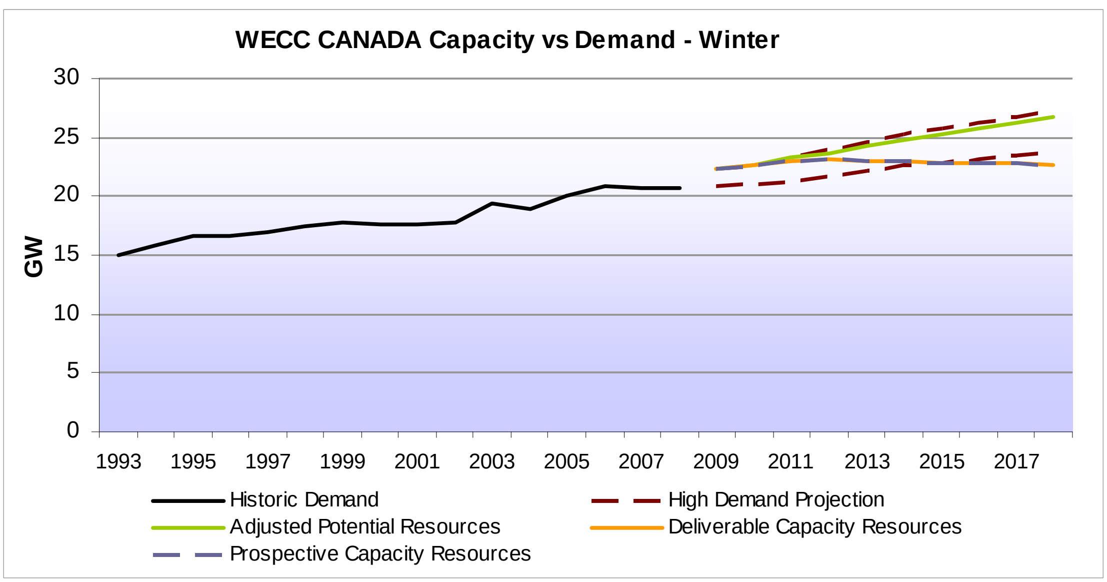


[107] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

For the 2009 to 2018 assessment period, WECC-CANADA Reserve Margins are projected to fall below the NERC Reference Margin Level by 2010 if no new resources are added. Even with the addition of all Future resources, a drop below the NERC Reference Margin Level is projected by 2011. WECC-CANADA may need additional the resources to meet NERC's Reference Margin Level through 2018.

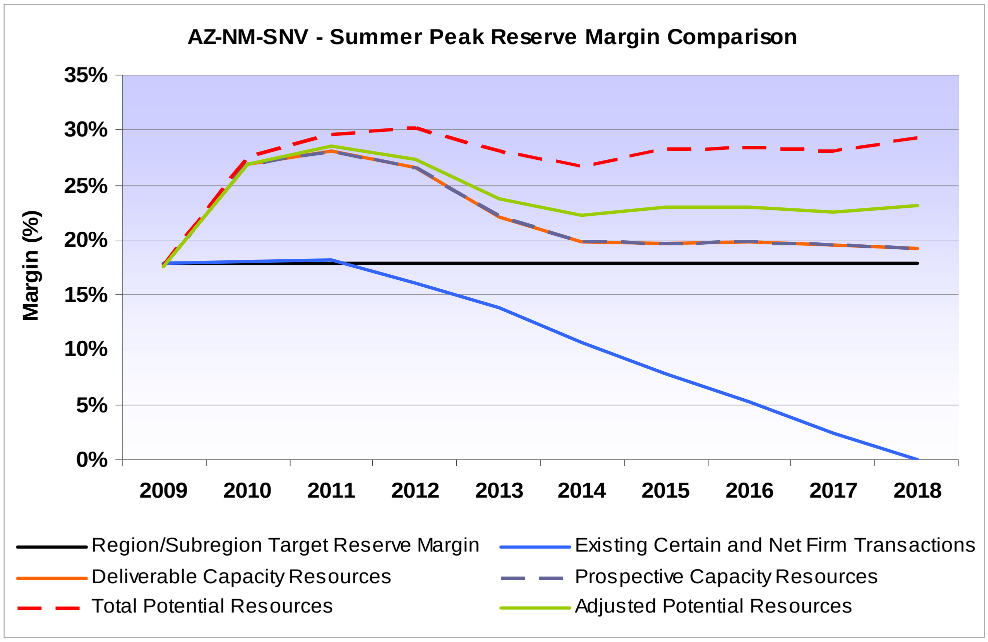


For the high demand projection,[108] WECC-CANADA capacity resources, with all categories considered, are projected to remain below NERC's Reference Margin Level through the 2009 to 2018 assessment period. Without the addition of resources, adequacy concerns may be further exacerbated.

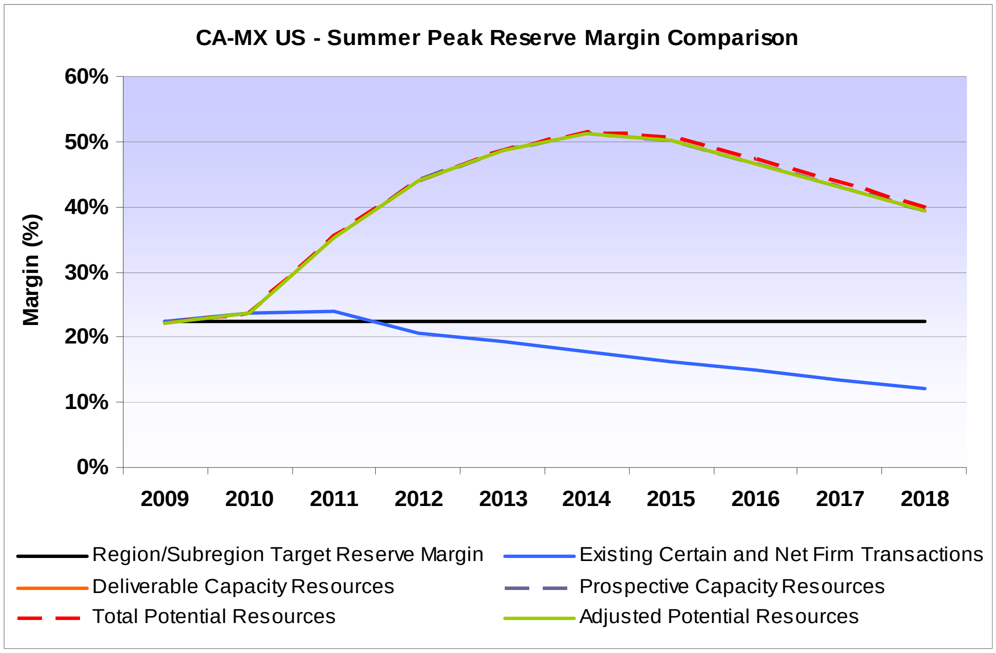


[108] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

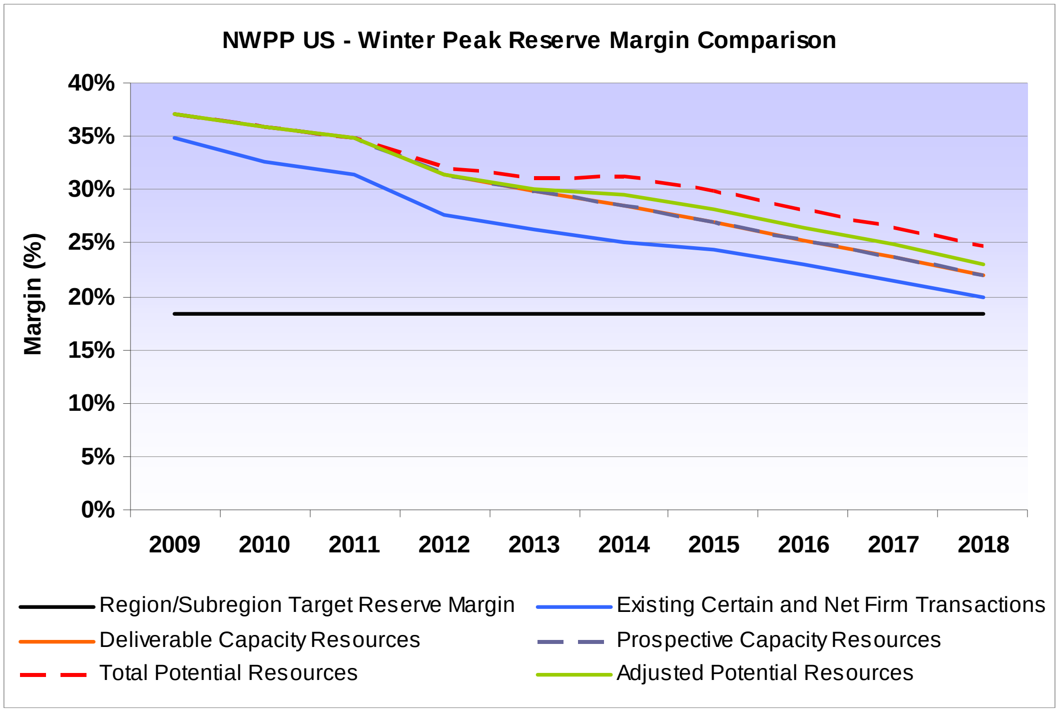
For the 2009 to 2018 assessment period, WECC-AZ-NM-SNV Reserve Margins are projected to fall below the NERC Reference Margin Level by 2012 if no new resources are added. With the addition of Future resources, the Reserve Margins should remain above the NERC Reference Margin Level.



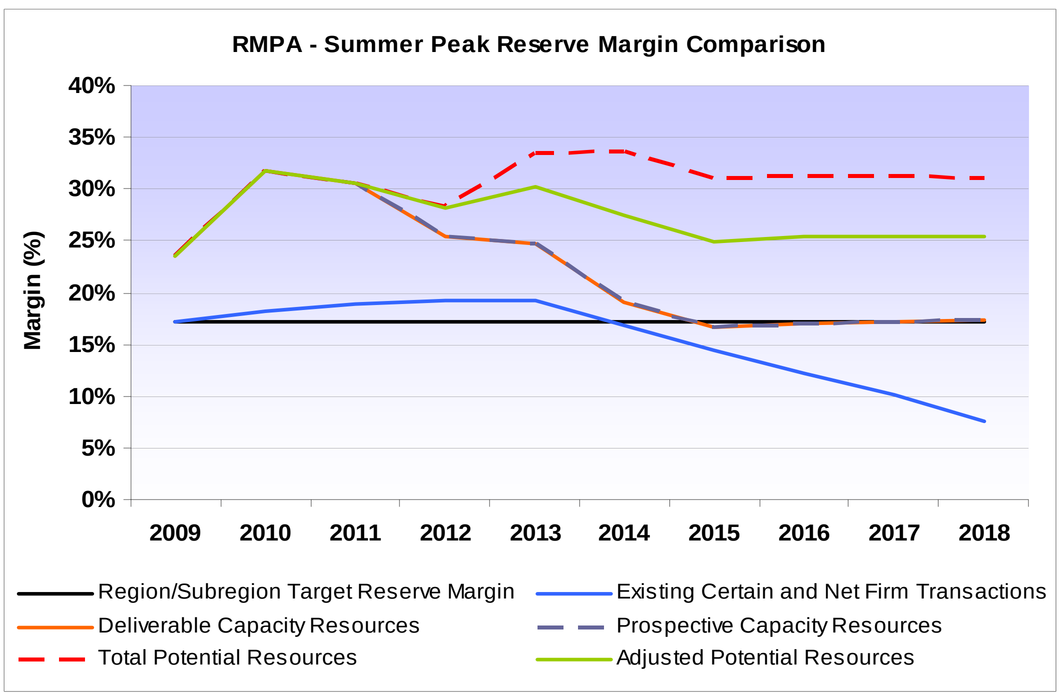
For the 2009 to 2018 assessment period, WECC-AZ-NM-SNV Reserve Margins are projected below the NERC Reference Margin Level by 2012, if no new resources are added. With the addition of Future resources, Reserve Margins should remain above the NERC Reference Margin Level.



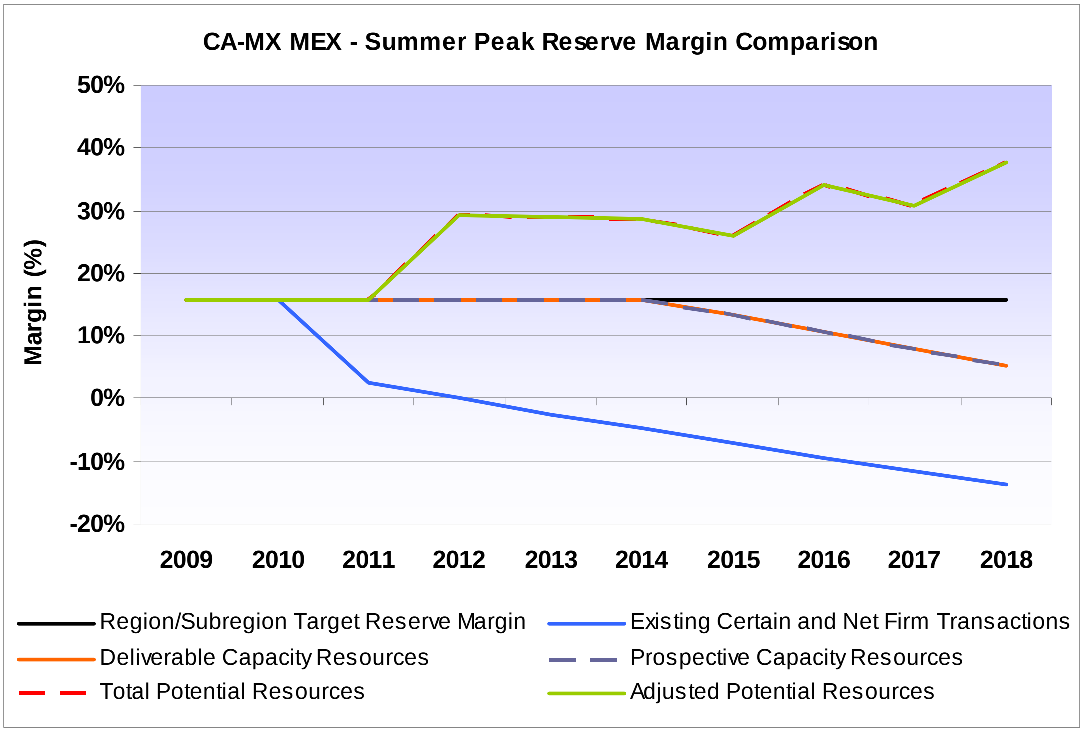
For the 2009 to 2018 assessment period, WECC-NWPP (US) Reserve Margins (winter) are projected to remain above the NERC Reference Margin Level through 2018.



For the 2009 to 2018 assessment period, WECC-RMPA Reserve Margins are projected to fall slightly below the NERC Reference Margin Level by 2015. However, for the remainder of the assessment period resources appear adequate.



For the 2009 to 2018 assessment period, WECC-CA-MX-Mexico Reserve Margins are projected to fall below the NERC Reference Margin Level by 2011 if no new resources are added. Even with the addition of all Future resources, a drop below the NERC Reference Margin Level is projected by 2015. WECC-CA-MX-Mexico may need additional resources to remain above the NERC Reference Margin level through 2018.



Eastern Interconnection Highlights

FRCC Highlights

FRCC expects to have adequate generating reserves with transmission system deliverability throughout the ten-year planning horizon. In addition, Existing Other merchant plant capability of 953 MW to 1,337 MW is potentially available as Future resources to FRCC members and others.

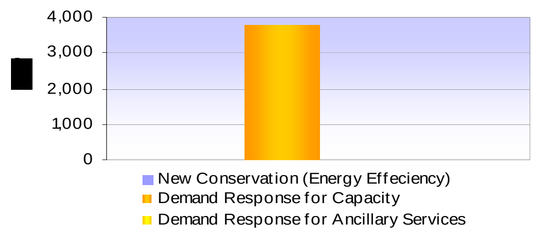
The transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand and provide planned firm transmission service. Operational issues can develop due to unplanned outages of generating units within the FRCC Region. However, it is anticipated that existing operational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

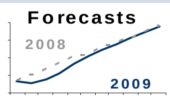
FRCC

Regional Long-Term Assessment Summary

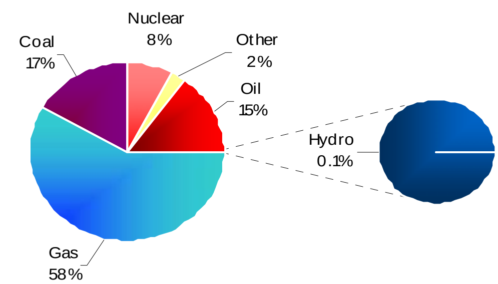
Summer Peak Demand	2009	2018
Total Internal Demand (MW)	45,734	53,689
Direct Control Load Management	2,452	3,019
Contractually Interruptible (Curtailable)	751	785
Critical Peak-Pricing with Control	0	0
Load as a Capacity Resource	0	0
Net Internal Demand (MW)	42,531	49,885

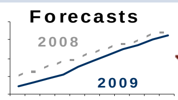
Demand-Side Management - 2018



Energy Consumption		2009	2017
Net Energy to Load (GWh)		226,874	260,956
Percentage Change from 2008 Forecast		-8.9%	15.5%

Relative Capacity Mix by Fuel Type - 2009

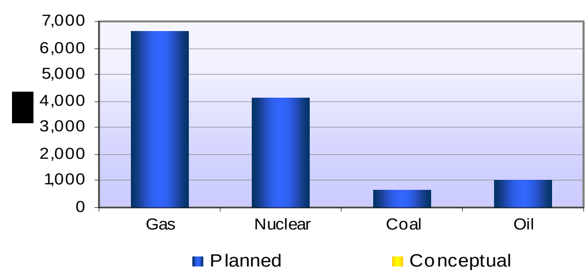


Peak Demand Comparison		2009	2017
2008 Demand Forecast		48,181	57,346
Percentage Change from 2008 Forecast		-5.1%	-8.6%

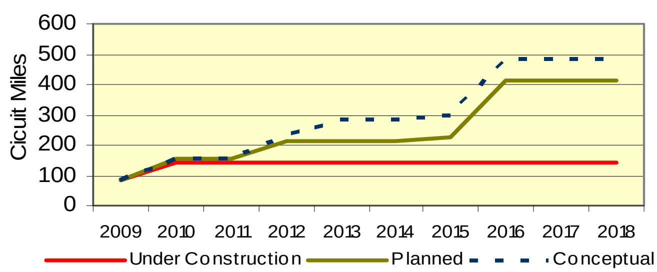
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	49,239	15.8%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	63,336	27.0%
Prospective Capacity Resources	63,336	27.0%
Adjusted Potential Capacity Resources	63,336	27.0%
Total Potential Capacity Resources	64,690	29.7%
NERC Reference Margin Level	-	15.0%

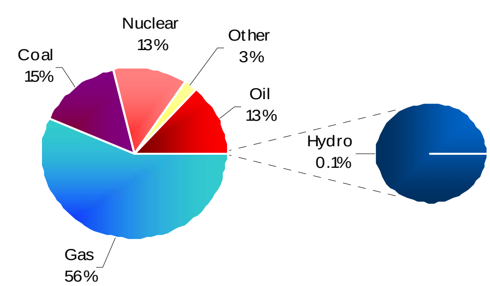
Projected On-Peak Fuel-Mix 10 Year Change



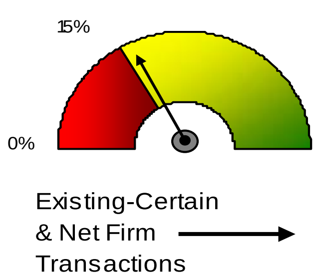
Projected Transmission Additions



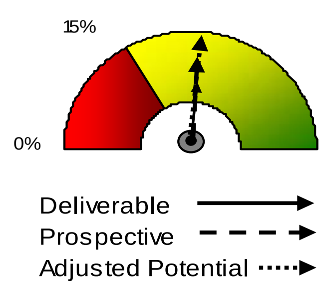
Relative Capacity Mix by Fuel Type - 2018



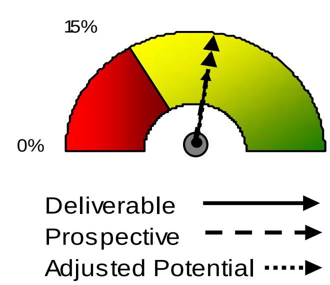
2009 Reserve Margin



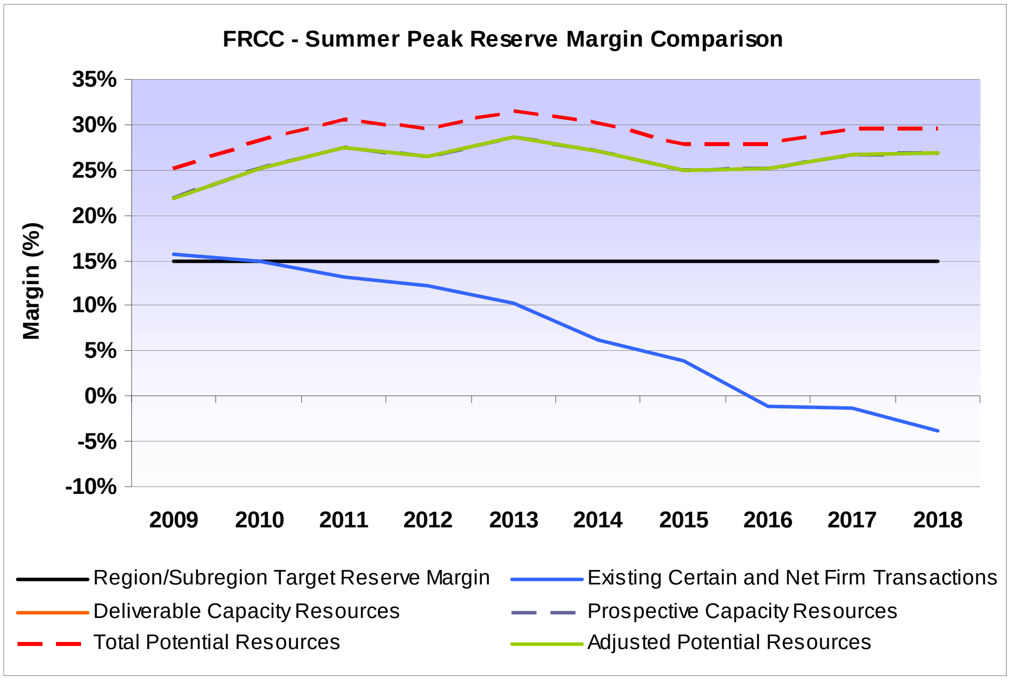
2013 Reserve Margins



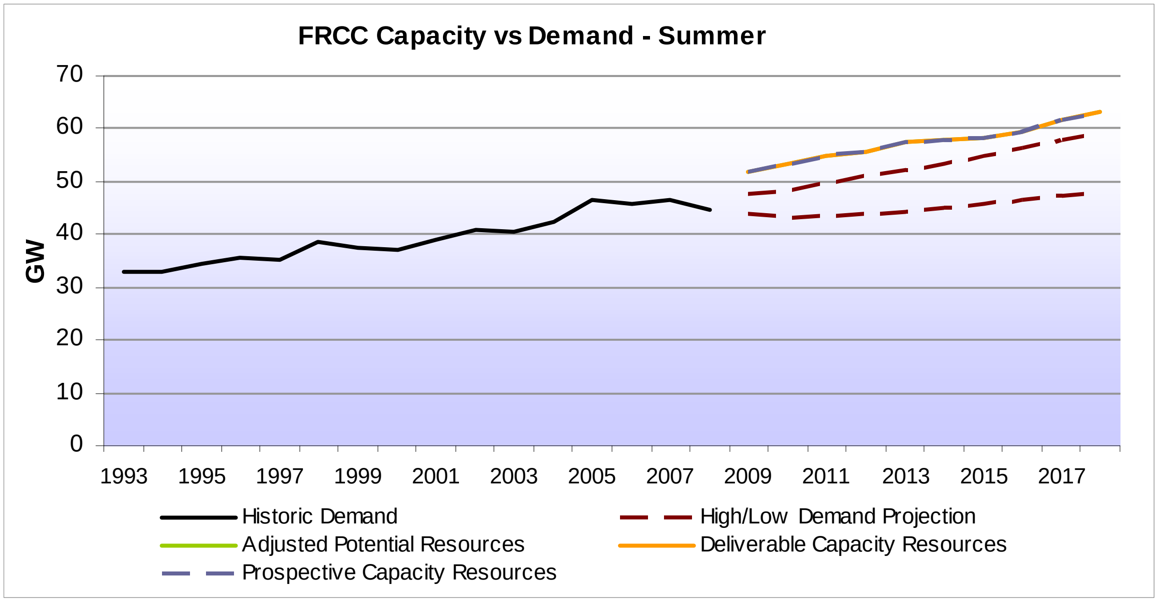
2018 Reserve Margins



For the 2009 to 2018 assessment period, FRCC Reserve Margins are projected to fall below the NERC Reference Margin Level by 2010 if no new resources are added. With the addition of Future resources, the FRCC reserve margins should remain above the NERC Reference Margin Level.



For the high demand projection,[109] the FRCC capacity resources appear above the NERC Reference Margin level during the assessment period when considering all categories of capacity resources.



[109] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

MRO Highlights

The Midwest Reliability Organization (MRO) is a Cross-Border Regional Entity representing the upper Midwest of the United States and Canada. MRO is organized consistent with the Energy Policy Act of 2005 and the bilateral principles between the United States and Canada.

Sufficient generating capacity is expected within the MRO Region to maintain adequate Reserve Margins through 2018. With Adjusted Conceptual resources included from the generation interconnection queues in the MRO Region, a proxy target Reserve Margin level of 15 percent for the five Planning Authorities is expected to be met through 2018. The Reserve Margin for the MRO-US subregion is met through 2017.

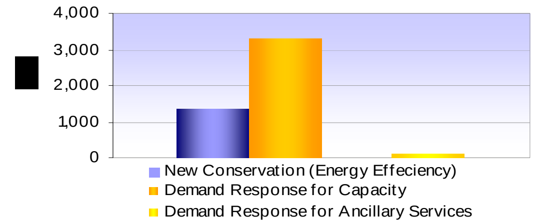
Through the 2018 planning horizon, the MRO expects its transmission system to perform adequately assuming proposed reinforcements are completed on schedule. The MRO Transmission Owners estimate that 833 miles of 500 kV dc circuit, 2,514 miles of 345 kV circuit and 904 miles of 230 kV circuit could be installed in the MRO Region over the next ten years. Continued power market activity will fully utilize the capability of the system, but there may be times when the transmission system may not meet all market needs.

MRO

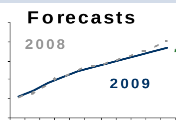
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	50,575	57,967
Direct Control Load Management	1,446	1,469
Contractually Interruptible (Curtailable)	1,740	1,845
Critical Peak-Pricing with Control	0	0
Load as a Capacity Resource	0	0
Net Internal Demand (MW)	47,388	54,654

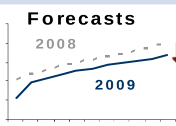
Demand-Side Management - 2018



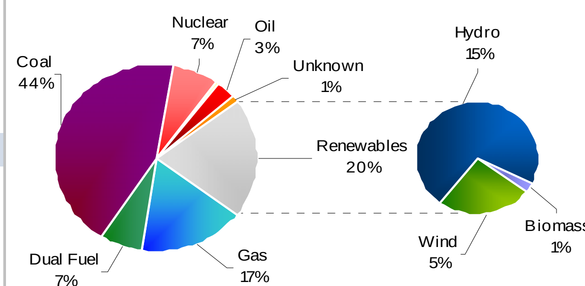
Energy Consumption	2009	2017
Net Energy to Load (GWh)	279,433	318,855
Percentage Change from 2008 Forecast	1.6%	-0.8%



Peak Demand Comparison	2009	2017
2008 Demand Forecast	51,792	58,668
Percentage Change from 2008 Forecast	-2.3%	-4.5%



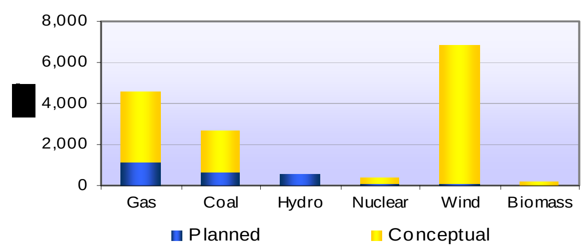
Relative Capacity Mix by Fuel Type - 2009



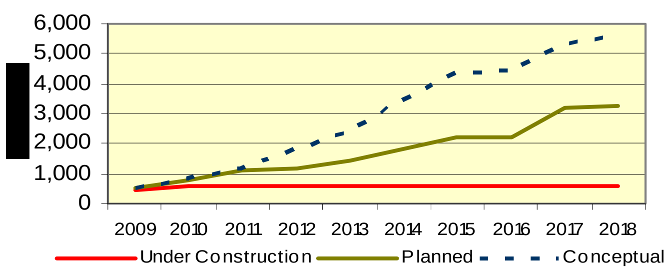
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	57,020	20.3%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	59,438	8.8%
Prospective Capacity Resources	59,567	9.0%
Adjusted Potential Capacity Resources	64,607	18.2%
Total Potential Capacity Resources	75,783	38.7%
NERC Reference Margin Level	-	15.0%

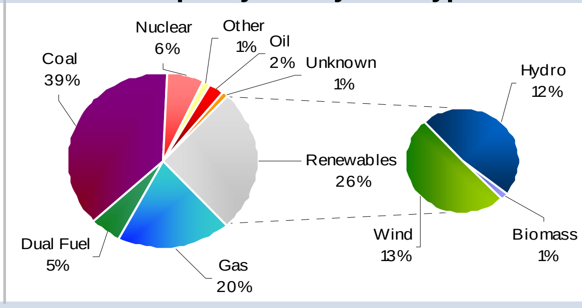
Projected On-Peak Fuel-Mix 10 Year Change



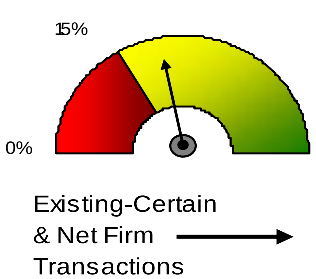
Projected Transmission Additions



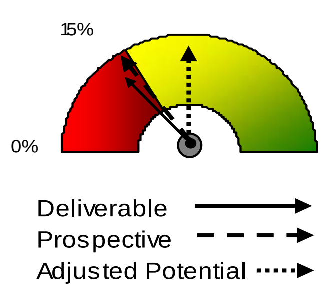
Relative Capacity Mix by Fuel Type - 2018



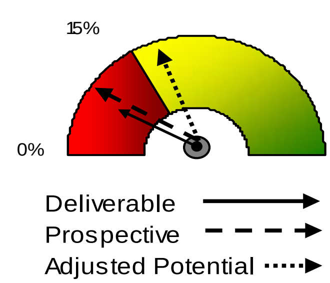
2009 Reserve Margin



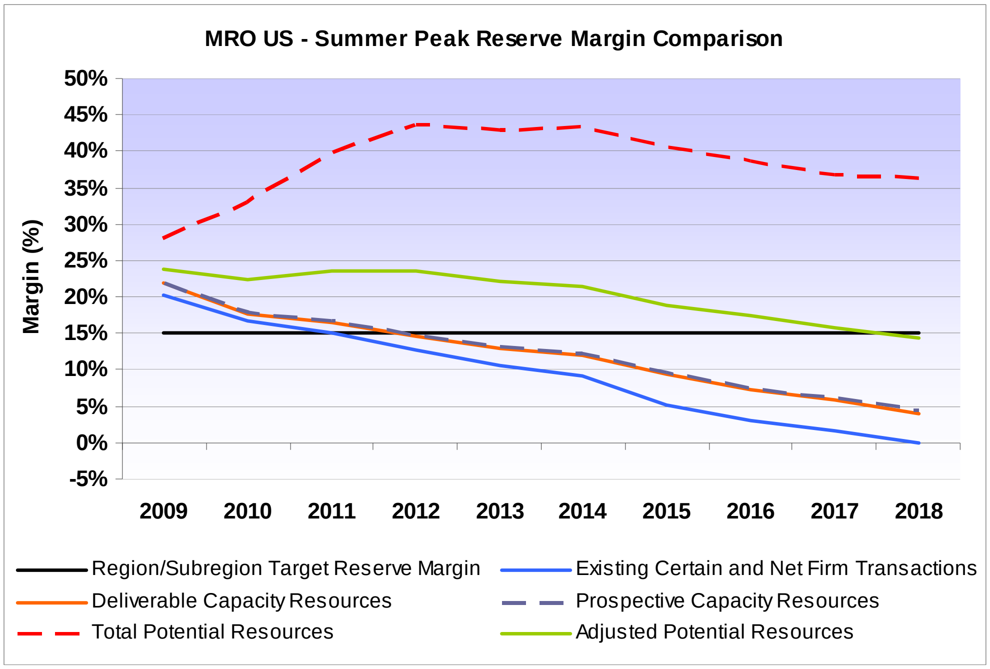
2013 Reserve Margins



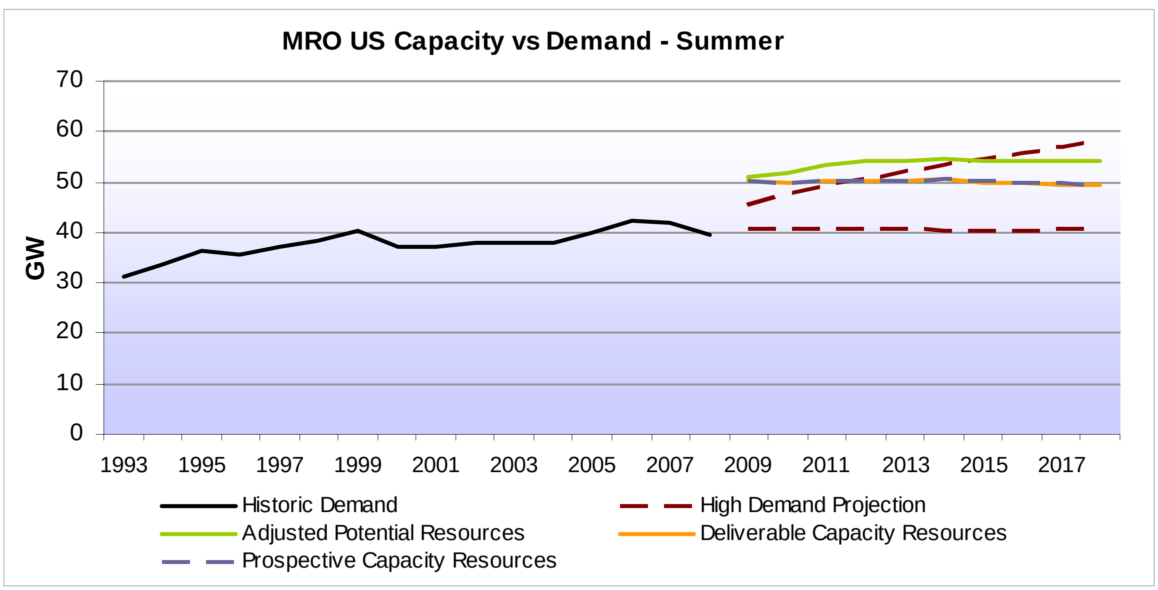
2018 Reserve Margins



For the 2009 to 2018 assessment period, MRO-US Reserve Margins are projected to fall below the NERC Reference Margin Level by 2012 if no new resources are added. Even with the addition of all Future resources, a drop below the NERC Reference Margin Level is projected by 2012. MRO-US may need additional resources to remain above the NERC Reference Margin level through 2018.

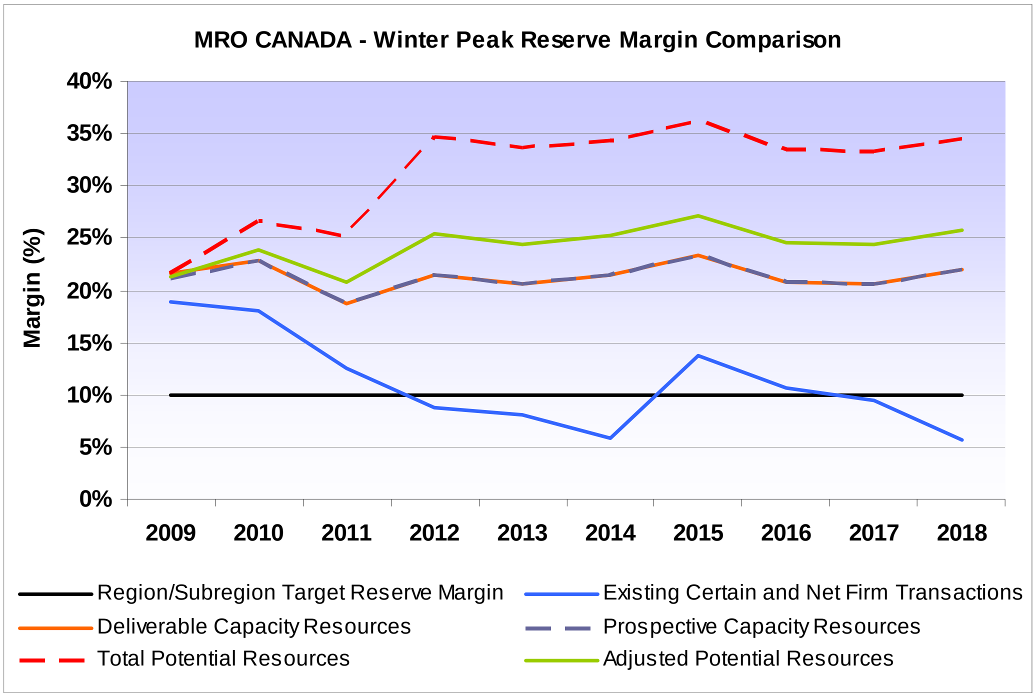


For the high demand projection[110], MRO-US capacity resources, with all categories considered, are projected to remain below the NERC Reference Margin Level through the 2010 to 2018 assessment period. Without the addition of resources, concerns are further exacerbated.

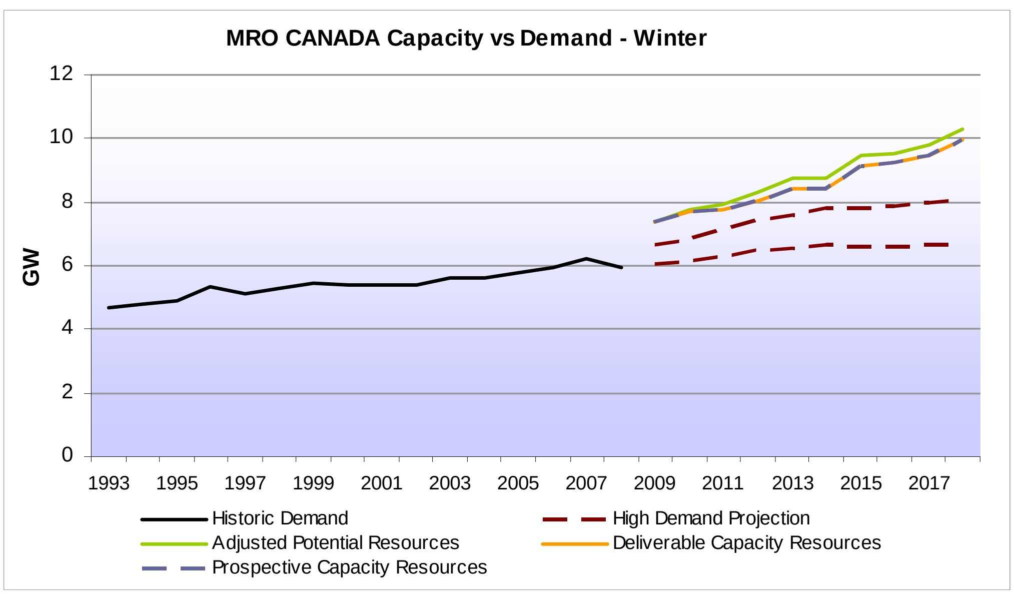


[110] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

For the 2009 to 2018 assessment period, MRO-CANADA Reserve Margins are projected to fall below the NERC Reference Margin Level by 2012 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin.



For the high demand projection[111], MRO-CANADA capacity resources appear above the NERC Reference Margin level during the assessment period when considering all categories of capacity resources.



[111] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

RFC Highlights

Both RTOs (PJM and MISO) within Reliability*First* are projected to have sufficient Reserve Margins for this assessment period. Therefore, the Reliability*First* Region is expected to have adequate reserves also.

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.

The aggregate connected Net Internal Demand (NID) in the Reliability*First* Region for the summer peak is projected to increase by about 23,000 MW from 169,900 MW in 2009, to 193,100 MW in 2018. The compound annualized growth rate (CAGR) in Net Internal Demand for the ten-year period 2009 to 2018 is 1.4 percent per year.

The reported existing and planned generating unit capacity for the summer of 2009 is 215,600 MW. The result of Future, Planned capacity changes and generator retirements is a projected net increase of 4,000 MW through 2018. Approximately 8,500 MW, or 18.4 percent of the 46,400 MW in conceptual generator capacity from the PJM and MISO generator queues are also expected through 2018. This is a total expected increase of 12,600 MW to 228,100 MW. With an expected import of 200 MW, the Regional capacity resources are 228,300 MW.

When projected capacity additions are included with existing resources, the PJM reserve margin remains at or above 16.2 percent and the MISO reserve margin remains above 15.4 percent through 2018. Since PJM and MISO reserve margins remain above their target values through 2018, Reliability*First* expects to have adequate resources.

Plans within Reliability*First* for the next seven years include the addition of over 1,700 miles of high voltage transmission lines that will operate at 100 kV and above, as well as numerous new substations and transformers that are expected to enhance and strengthen the bulk transmission system. Most of the new additions are connections to new generators or substations.

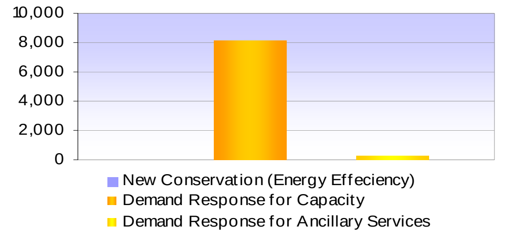
No other unusual operating conditions that could impact reliability are foreseen for this assessment period. Reliability*First* has no specific reliability concerns for this long term reliability assessment.

RFC

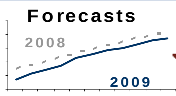
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	178,100	201,300
Direct Control Load Management	1,100	1,100
Contractually Interruptible (Curtailable)	7,100	7,100
Critical Peak-Pricing with Control	0	0
Load as a Capacity Resource	0	0
Net Internal Demand (MW)	169,900	193,100

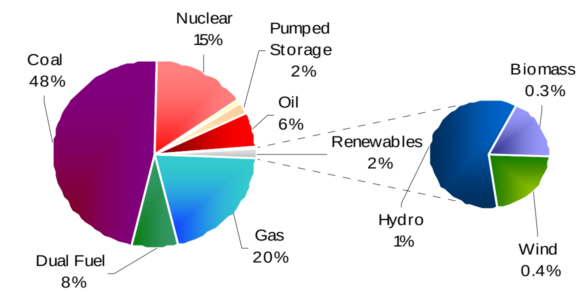
Demand-Side Management - 2018



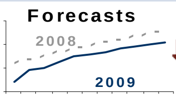
Energy Consumption		2009	2017
Net Energy to Load (GWh)	Forecasts	958,792	1,076,062
Percentage Change from 2008 Forecast		-2.6%	-1.8%



Relative Capacity Mix by Fuel Type - 2009



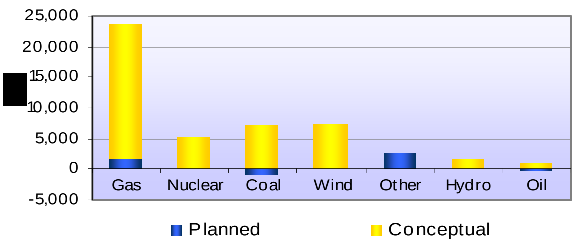
Peak Demand Comparison		2009	2017
2008 Demand Forecast	Forecasts	187,100	208,600
Percentage Change from 2008 Forecast		-4.8%	-4.3%



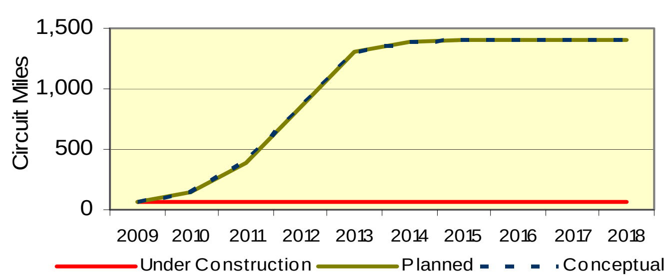
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	215,700	27.0%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	219,800	13.8%
Prospective Capacity Resources	221,500	14.7%
Adjusted Potential Capacity Resources	230,054	19.1%
Total Potential Capacity Resources	267,900	38.7%
NERC Reference Margin Level	-	15.0%

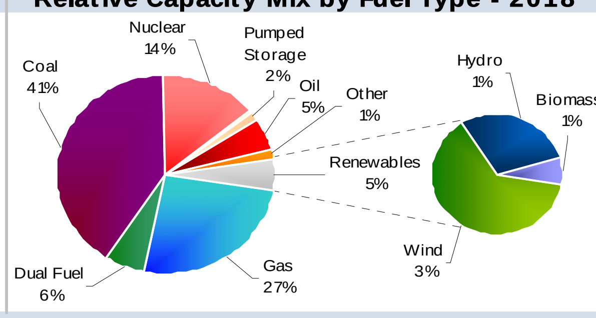
Projected On-Peak Fuel-Mix 10 Year Change



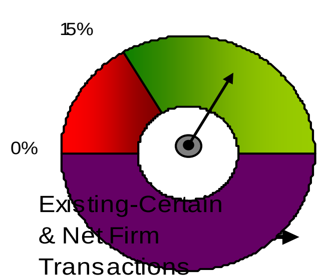
Projected Transmission Additions



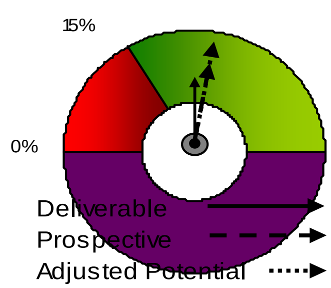
Relative Capacity Mix by Fuel Type - 2018



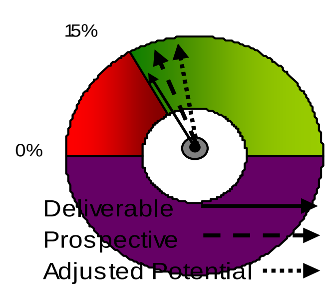
2009 Reserve Margin



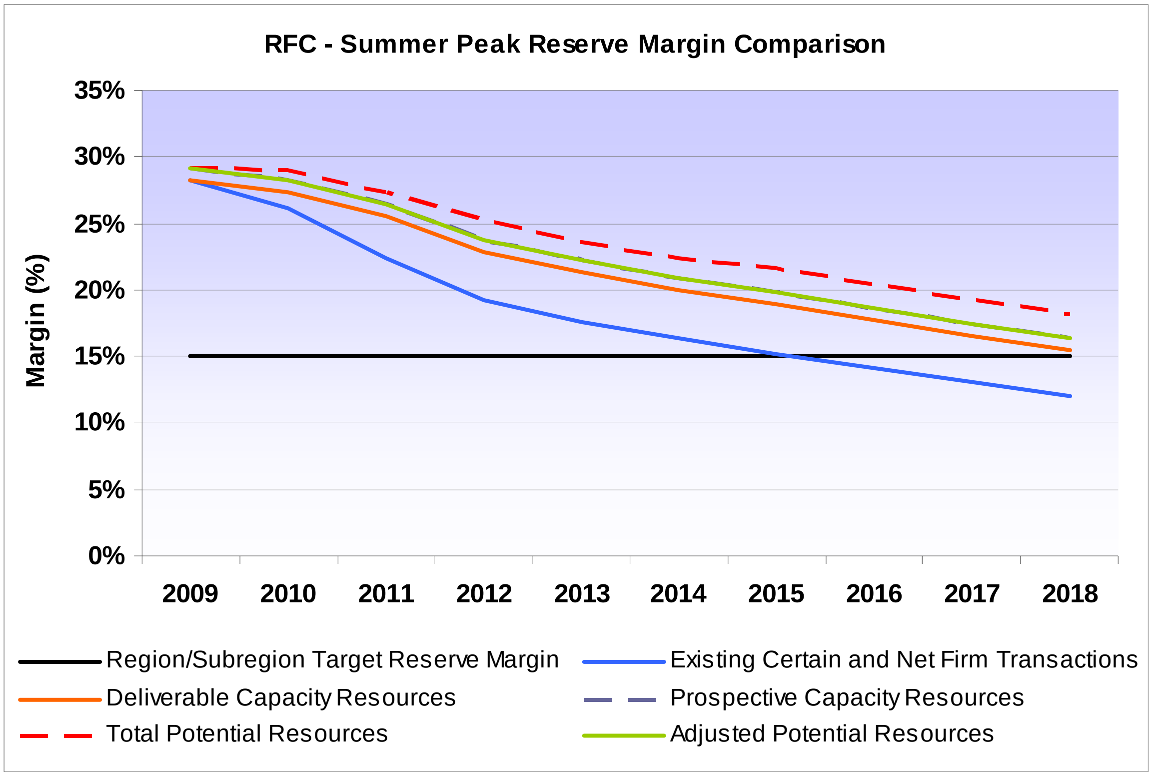
2013 Reserve Margins



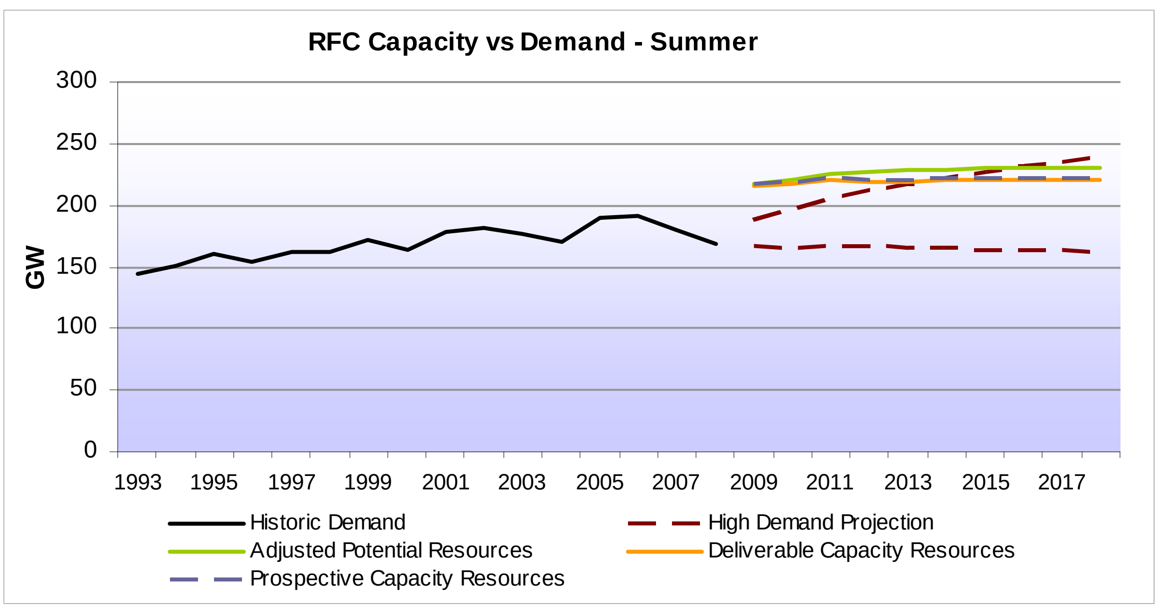
2018 Reserve Margins



For the 2009 to 2018 assessment period, RFC Reserve Margins are projected to fall below the NERC Reference Margin Level by 2016 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.

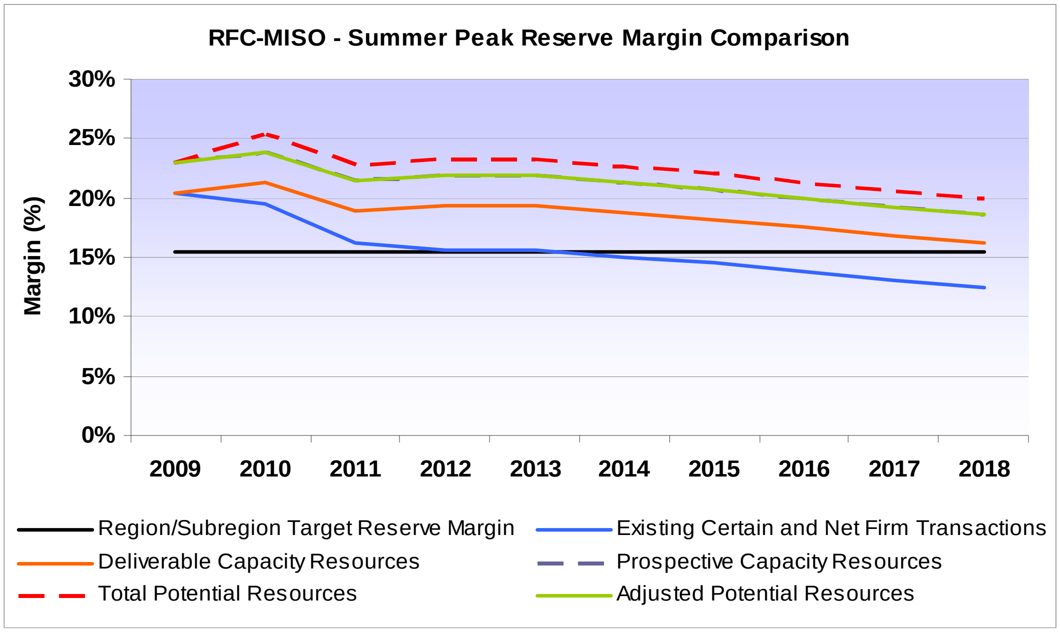


For the high demand projection[112], RFC capacity resources, with all categories considered, are projected to remain adequate through 2014.

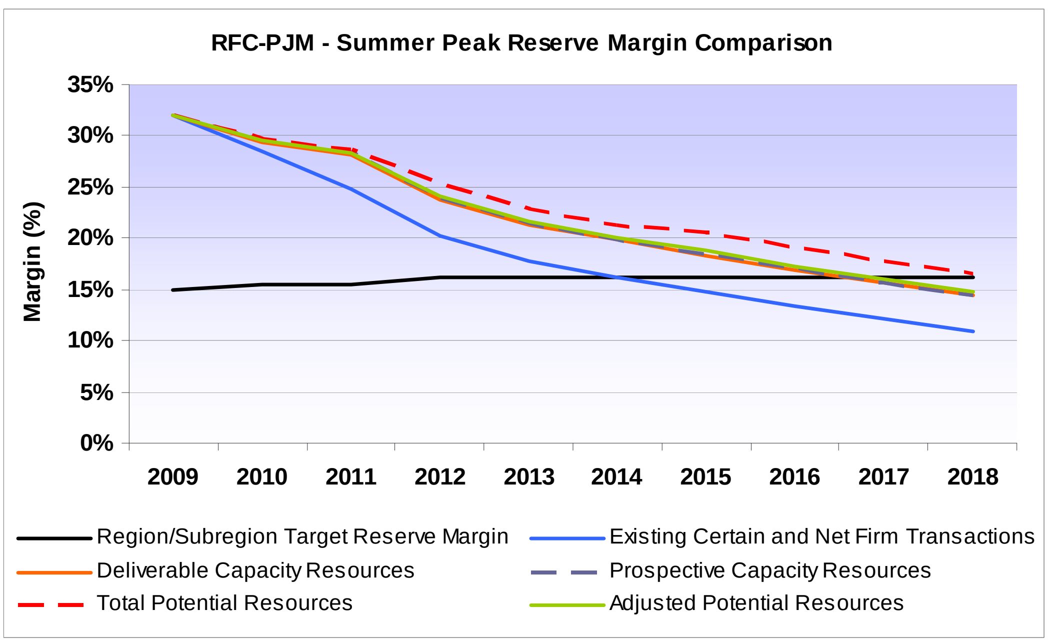


[112] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

For the 2009 to 2018 assessment period, RFC-MISO Reserve Margins are projected to fall below the NERC Reference Margin Level by 2014 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.



For the 2009 to 2018 assessment period, RFC-PJM Reserve Margins are projected to fall below the NERC Reference Margin Level by 2014 if no new resources are added. RFC-PJM increased their NERC Reference Margin Level[113] during the study period to represent changes in their system. All Conceptual resources may be needed to meet the NERC Reference Margin Level in 2018.



[113] The increase in the NERC Reference Margin Level is due to the increased Reserve Margin requirement in PJM to 16.2% in 2012.

SERC Highlights

The capacity figures provided in the 2009 *Long-Term Reliability Assessment* are based on the data submitted to fulfill utility reporting requirements under DOE-EIA 411 report. For this report, there is a significant improvement in reporting over the SERC report in the *2008 Long-Term Reliability Report*.

Capacity resources in the Region as a whole are expected to be adequate throughout the long-term assessment period. Reported potential capacity additions and existing capacity, including uncommitted resources, along with the necessary transmission system upgrades, are projected to satisfy reliability needs through 2018.

Utilities in the SERC Region invested approximately $1.5 billion in transmission system upgrades 100 kV and above in 2008. The utilities plan to invest approximately $1.7 billion in 2009 and are planning transmission capital expenditures of more than $8.8 billion over the next five years. There are over 1,400 miles of planned transmission additions over the next 10 years at voltages of 100 kV and greater.

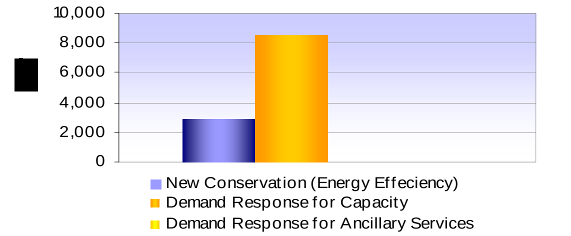
SERC

Regional Long-Term Assessment Summary

Summer Peak Demand

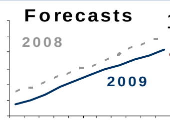
Summer Peak Demand	2009	2018
Total Internal Demand (MW)	202,738	237,386
Direct Control Load Management	972	3,023
Contractually Interruptible (Curtailable)	4,624	5,200
Critical Peak-Pricing with Control	0	41
Load as a Capacity Resource	271	260
Net Internal Demand (MW)	196,871	228,862

Demand-Side Management - 2018

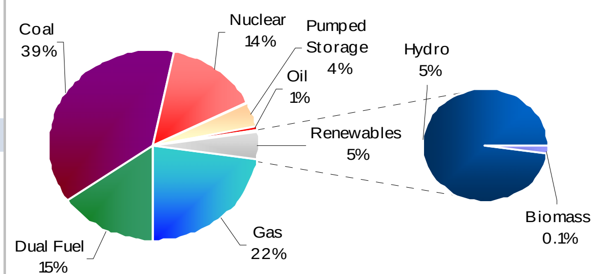


Energy Consumption

Energy Consumption	2009	2017
Net Energy to Load (GWh)	1,039,997	1,192,039
Percentage Change from 2008 Forecast	-4.3%	-3.3%

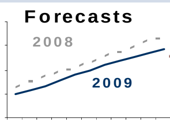


Relative Capacity Mix by Fuel Type - 2009



Peak Demand Comparison

Peak Demand Comparison	2009	2017
2008 Demand Forecast	209,288	243,056
Percentage Change from 2008 Forecast	-3.1%	-3.8%



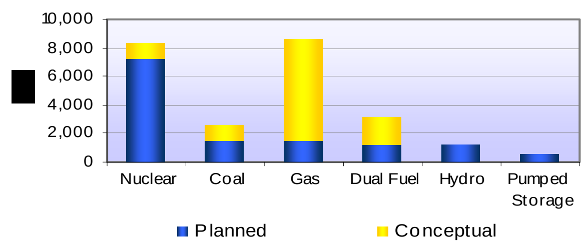
Capacity Resources On-Peak - 2009

Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	242,787	23.3%

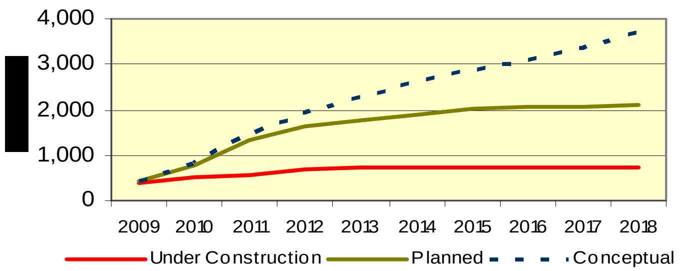
Capacity Resources On-Peak - 2018

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	262,372	14.6%
Prospective Capacity Resources	276,673	20.9%
Adjusted Potential Capacity Resources	276,748	20.9%
Total Potential Capacity Resources	290,774	27.1%
NERC Reference Margin Level	-	15.0%

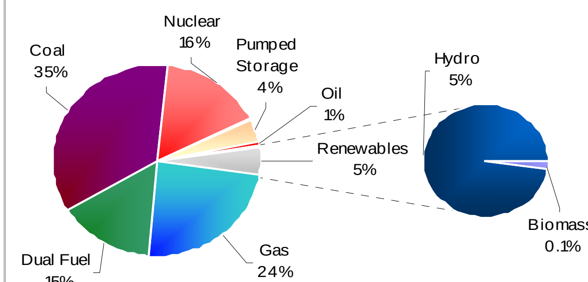
Projected On-Peak Fuel-Mix 10 Year Change



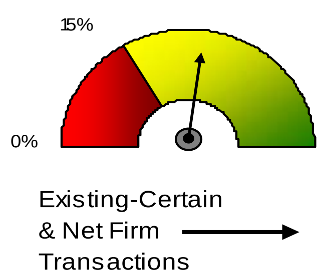
Projected Transmission Additions



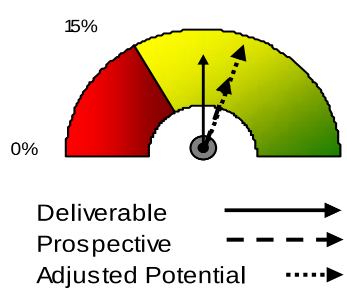
Relative Capacity Mix by Fuel Type - 2018



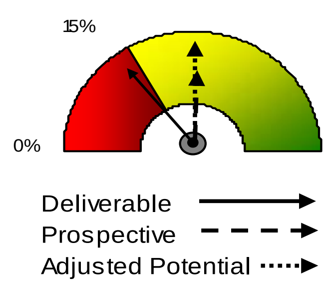
2009 Reserve Margin



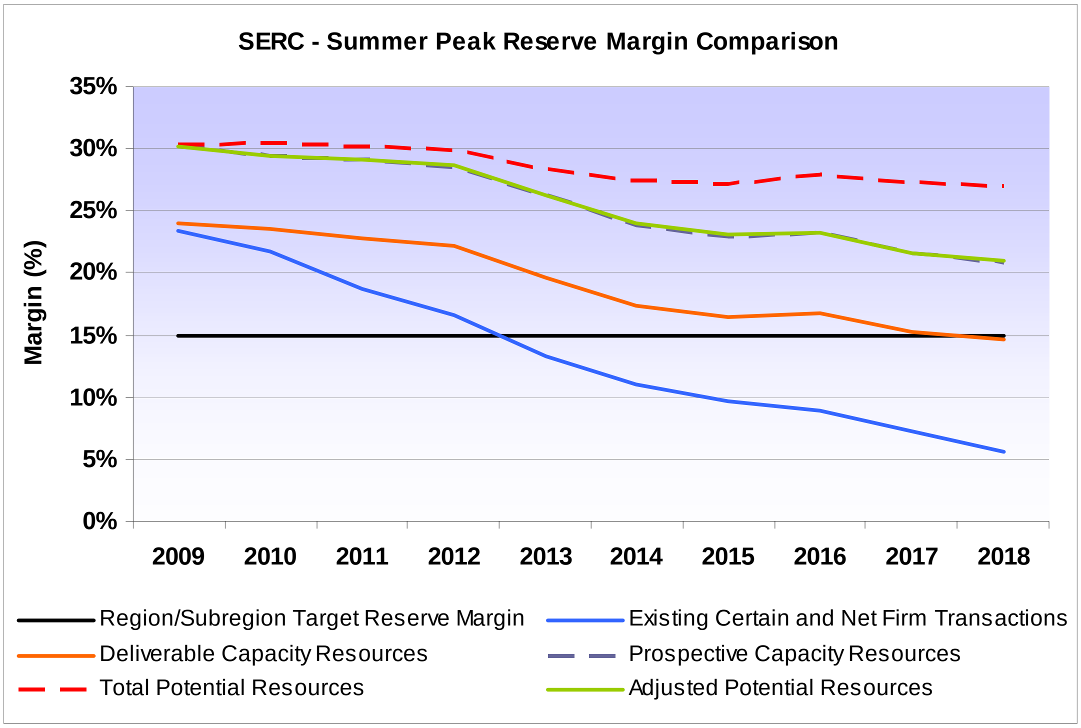
2013 Reserve Margins



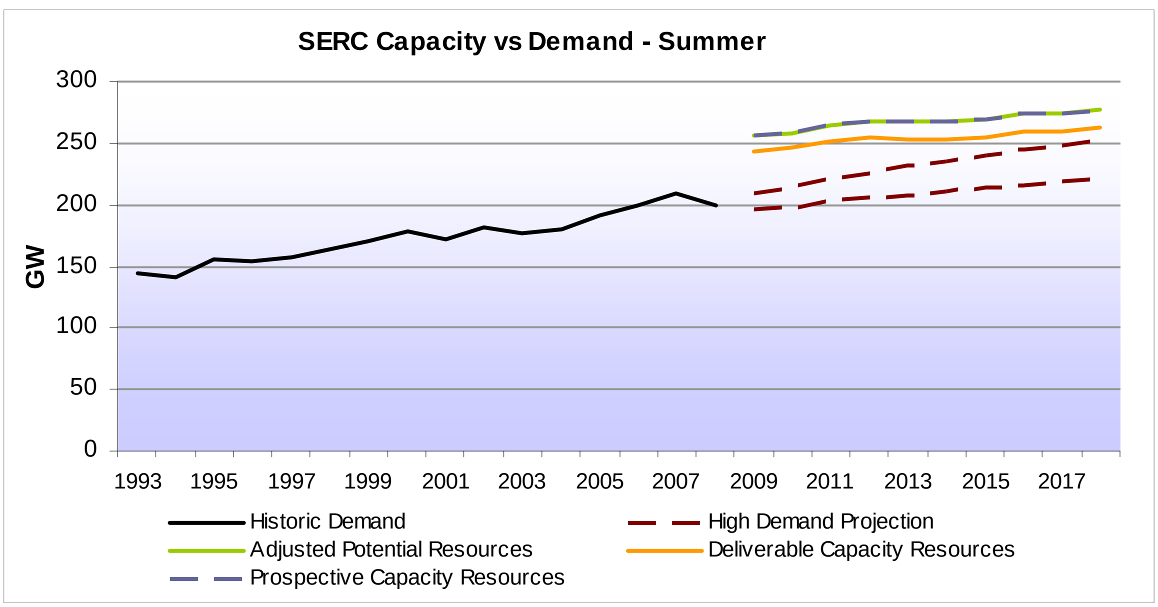
2018 Reserve Margins



For the 2009 to 2018 assessment period, SERC Reserve Margins are projected to fall below the NERC Reference Margin Level by 2013 if no new resources are added. With the addition of Future resources, the reserve margins appear to be higher than the NERC Reference Margin Level, but tight in 2018.

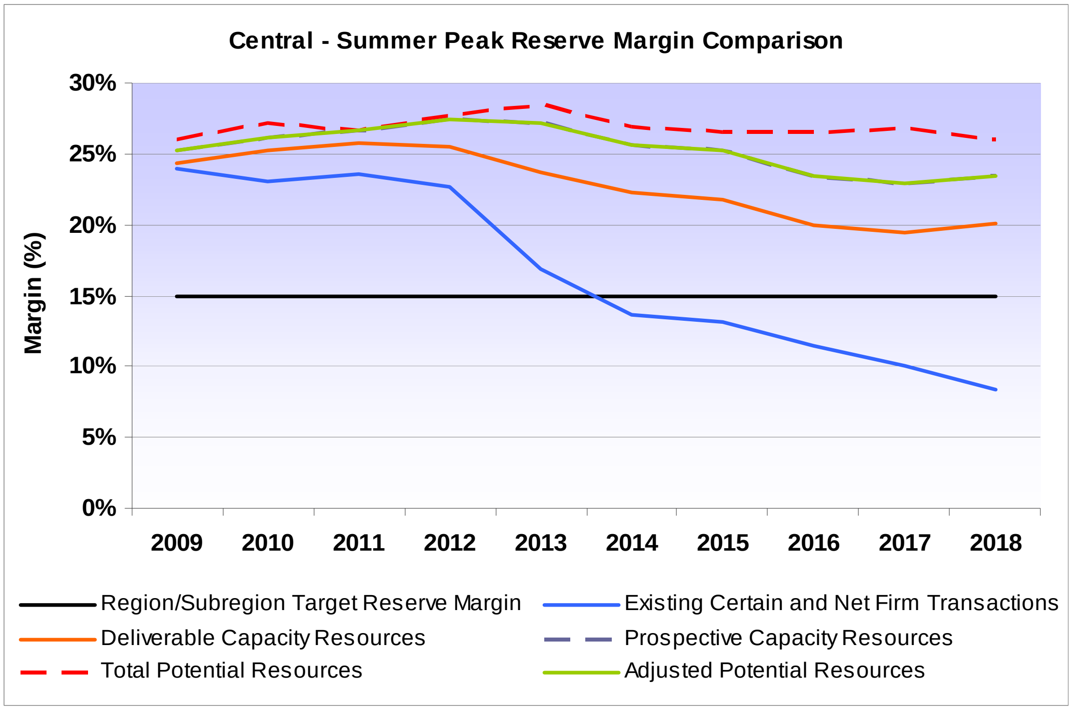


For the high demand projection[114], SERC capacity resources, with all categories considered, are projected to remain above the NERC Reference Margin Level through 2018.

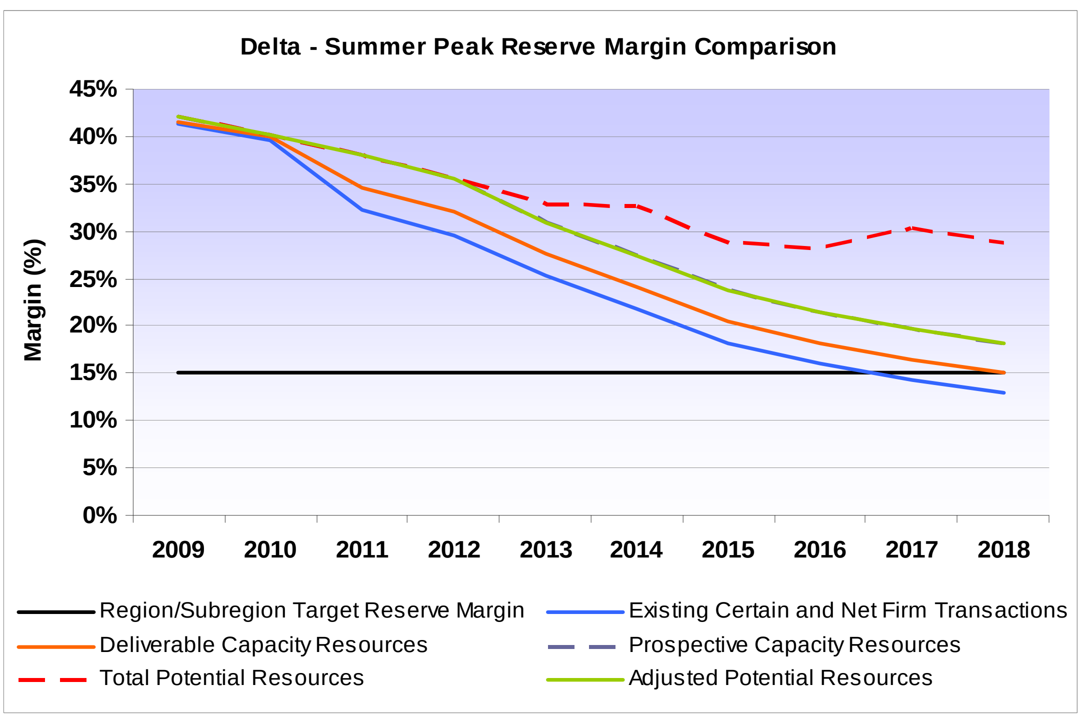


[114] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

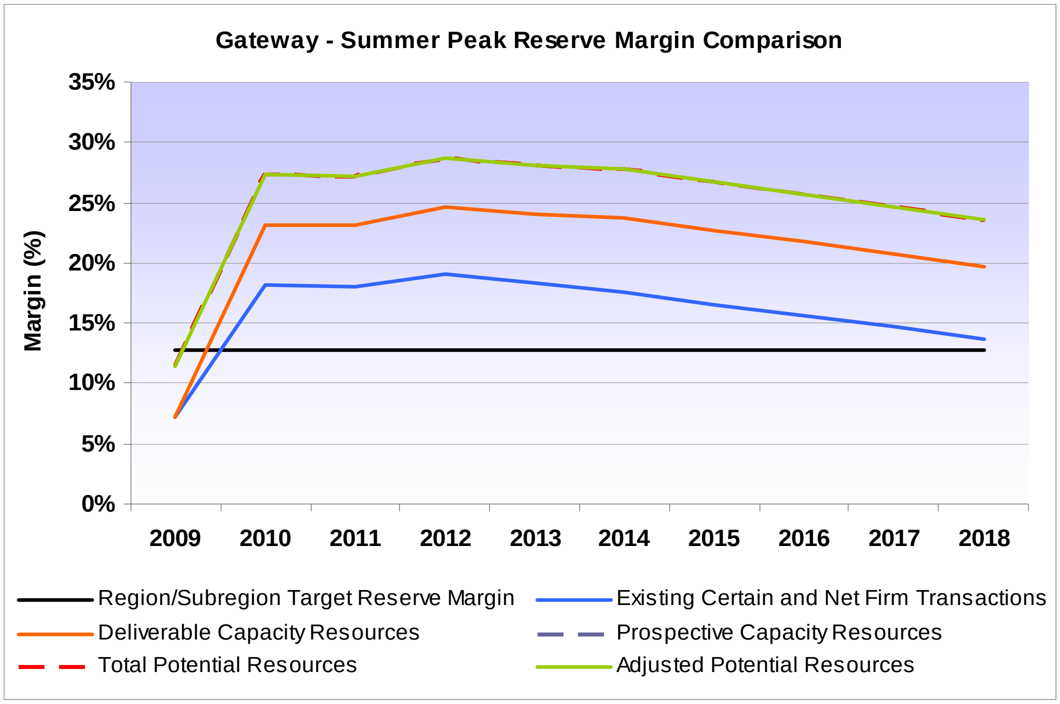
For the 2009 to 2018 assessment period, SERC-Central Reserve Margins are projected below the NERC Reference Margin Level by 2014 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.



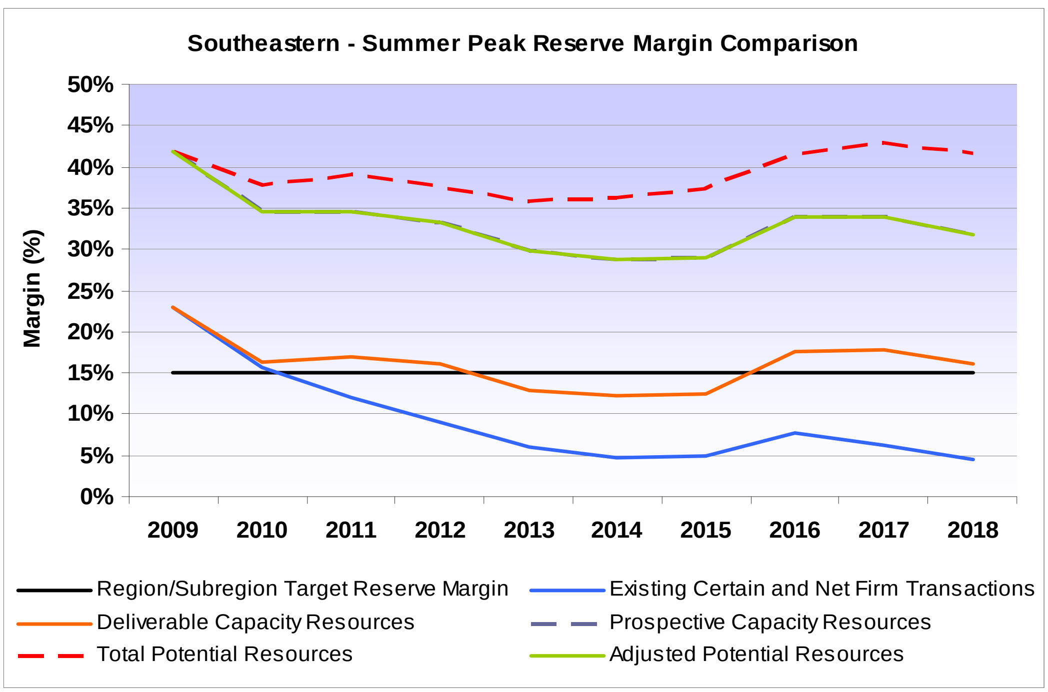
For the 2009 to 2018 assessment period, SERC-Delta Reserve Margins are projected below the NERC Reference Margin Level by 2017 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.



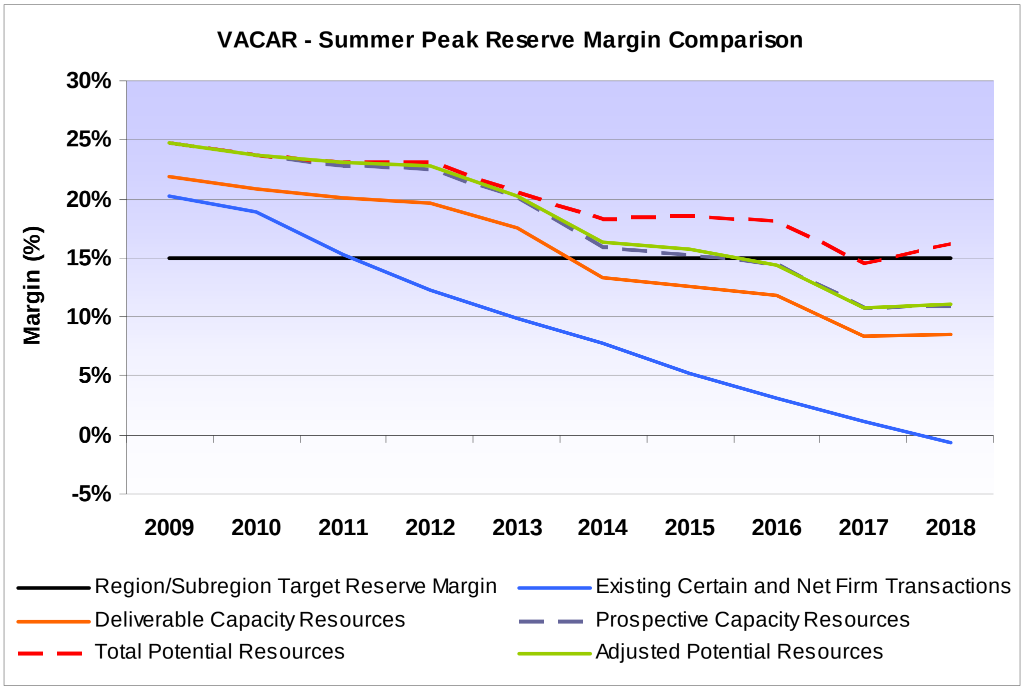
For the 2009 to 2018 assessment period, SERC-Gateway Reserve Margins are below the NERC Reference Margin Level for 2009. However, by 2010, all Reserve Margins are projected to remain above the NERC Reference Margin Level through 2018.



For the 2009 to 2018 assessment period, SERC-Southeastern Reserve Margins are projected below the NERC Reference Margin Level by 2011, if no new resources are added. Reserve Margins should be increased with the addition of Future resources through 2018.



For the 2009 to 2018 assessment period, SERC-VACAR Reserve Margins are projected below the NERC Reference Margin Level by 2012 if no new resources are added. Even with the addition of all Future resources, reserve margins are below the NERC Reference Margin Level, projected by 2016. SERC-VACAR may need the additional resources to remain above the NERC Reference Margin Level through 2018.



SPP Highlights

The SPP RTO Region is anticipating a steady and slow growth in demand with total system demand approaching 50,000 MW by 2018. Current SPP RTO demand is 44,500 MW.

The annual reserve margin for SPP is greater than the required 13.6 percent until the year 2016, where the margin drops to approximately 13 percent. For the remaining years (i.e., 2017 and 2018), SPP anticipates to meet reserve margin using potential capacity resources.

The SPP Transmission Expansion Plan 2009-2018 reported approximately 1,000 miles of bulk transmission lines and more than 10 transformers to address reliability needs. The SPP RC anticipates that the Acadiana Load Pocket will be a concern for the remainder of the 2009 summer. SPP is working with each entity in the area to resolve the issues and protect the load in the area. As a long-term solution, the SPP Independent Coordinator of Transmission (ICT) facilitated an agreement with members in the Acadiana pocket to expand and upgrade electric transmission in the area. In addition to the reliability needs, SPP RTO has implemented a Balanced Portfolio, which is a strategic initiative to develop a cohesive group of economic upgrades that benefit the SPP RTO Region, and for which costs will be allocated Regionally. Projects in the Balanced Portfolio are transmission upgrades of 345 kV or higher that will provide customers with potential savings that exceed the cost of the project. In April 2009, the SPP Regional State Committee and the Board of Directors/Members Committee approved Balance Portfolio projects totaling over $700 million, to be funded by the application of Federal Energy Regulatory Commission-approved “postage stamp” rates to SPP’s transmission-owning members across the Region.

The SPP Board of Directors recently approved the adoption of new planning principles and implementation of an Integrated Transmission Planning (ITP) Process. The ITP will consolidate SPP’s EHV Overlay, Balanced Portfolio, and ten-year reliability assessment into one consolidated process.

SPP as a Planning Authority conducts various reliability assessments to comply with NERC TPL Reliability Standards and coordinate the mitigation effort with its members. Based on the studies performed, SPP is not anticipating any near- or long-term reliability issues that have not addressed by any mitigation plan or local operating guides.

Since the implementation of the EIS market in 2007, SPP RTO continues an increase in the number of TLR events primarily due to the fact that SPP publishes congested facilities by issuing TLRs. SPP’s tariff and market protocols require the SPP RC to issue a TLR event in accordance with NERC TLR requirements each time congestion is experienced in the market footprint, even when it is only constraining economic use of transmission. SPP’s market protocols require issuing a TLR to announce that SPP is experiencing congestion.

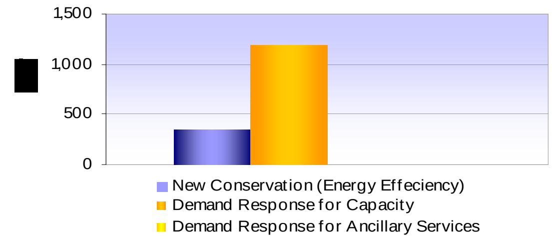
The penetration of wind generation in the western half of the SPP footprint is anticipated to have a significant impact on operations, due to wind's variable nature. SPP RTO currently has approximately 50,000 MW of wind in their Generation Interconnection queue. Additional data collection and situational awareness has been implemented to begin assessing regulation and spinning reserve needs. SPP formed a Wind Integration Task Force, which is responsible for conducting and reviewing studies to determine the impact of integrating wind generation into the SPP RTO transmission system and energy markets. These studies will include both planning and operational issues. The studies should lead to recommendations for developing new tools that may be required for the SPP RTO to properly evaluate requests for interconnecting wind generating resources to the transmission system.

SPP

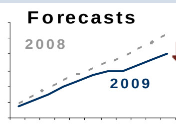
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	44,463	49,696
Direct Control Load Management	33	30
Contractually Interruptible (Curtailable)	484	527
Critical Peak-Pricing with Control	35	324
Load as a Capacity Resource	215	315
Net Internal Demand (MW)	43,696	48,500

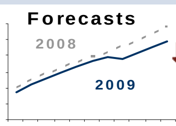
Demand-Side Management - 2018



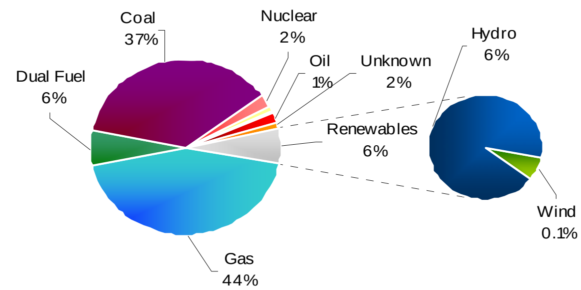
Energy Consumption		2009	2017
Net Energy to Load (GWh)		211,320	236,886
Percentage Change from 2008 Forecast		-0.7%	-3.9%



Peak Demand Comparison		2009	2017
2008 Demand Forecast		44,786	50,640
Percentage Change from 2008 Forecast		-0.7%	-3.2%



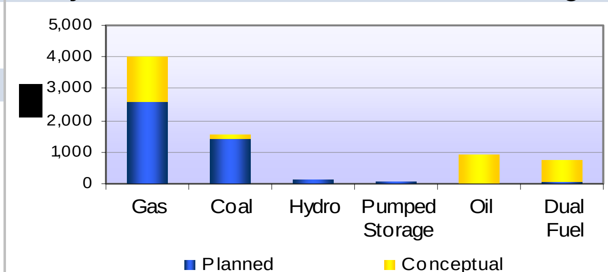
Relative Capacity Mix by Fuel Type - 2009



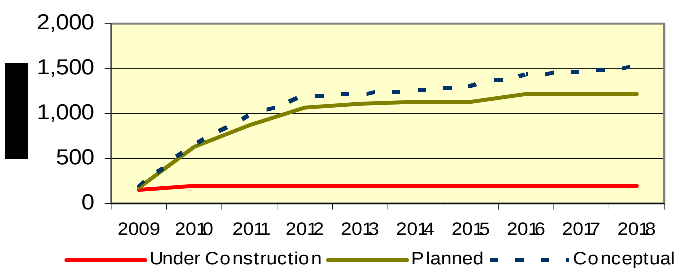
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	49,706	13.8%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	53,319	9.9%
Prospective Capacity Resources	59,846	23.4%
Adjusted Potential Capacity Resources	60,141	24.0%
Total Potential Capacity Resources	65,880	35.8%
NERC Reference Margin Level	-	13.6%

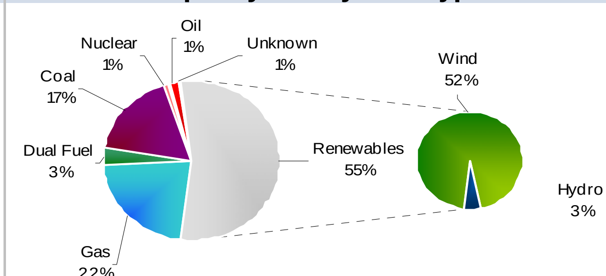
Projected On-Peak Fuel-Mix 10 Year Change



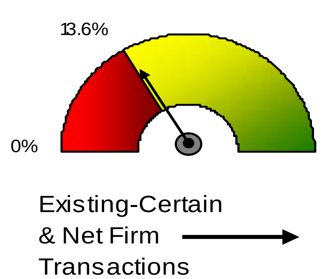
Projected Transmission Additions



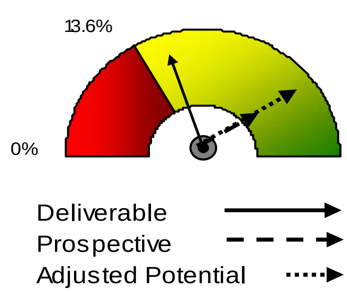
Relative Capacity Mix by Fuel Type - 2018



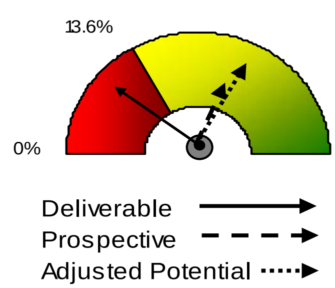
2009 Reserve Margin



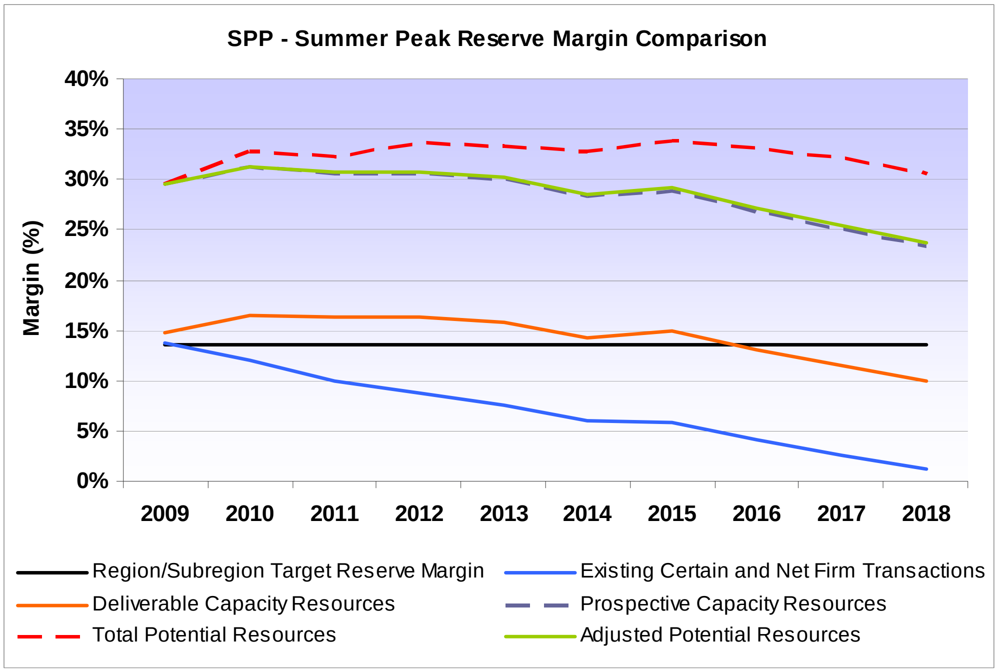
2013 Reserve Margins



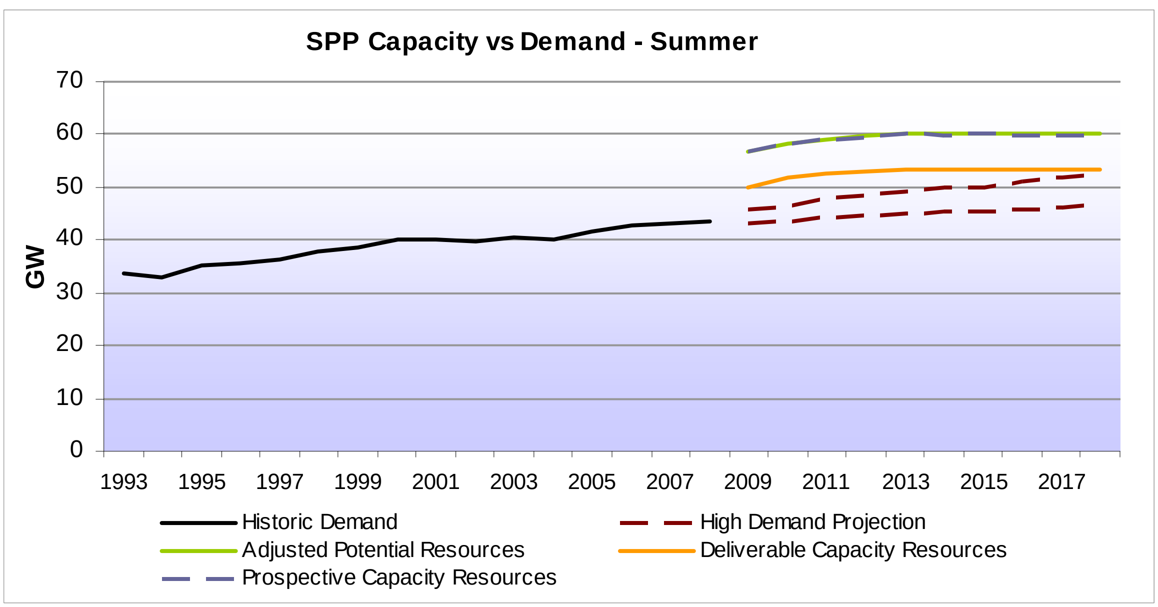
2018 Reserve Margins



For the 2009 to 2018 assessment period, SPP Reserve Margins are projected below the NERC Reference Margin Level by 2010 if no new resources are added. Even with the addition of Future, Planned resources, Reserve Margins are below the NERC Reference Margin Level by 2016. SPP may need the additional resources to remain above the NERC Reference Margin Level through 2018.



For the high demand projection,[115] SPP capacity resources, with all categories considered, remain higher than these forecasts through 2018.



[115] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

NPCC Highlights

Recognizing their diversity, the adequacy of NPCC is measured by assessing the five subregions, or areas, of NPCC : the Maritimes 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 (ISO New England Inc.), New York (New York ISO), Ontario (the Independent Electricity System Operator), and Québec (Hydro-Québec TransÉnergie). The Maritimes Area and Québec are predominantly winter-peaking systems. The Ontario, New York and New England Areas are summer-peaking systems. Consequently, the mix of winter- and summer-peaking areas would make an NPCC-wide comparison of year-to-year peaks misleading. Comparisons for the individual subregions follow. The expected growth, together with the overall reliability assessment of the projected transmission and resources, follows individually for the Maritimes Area, New England, New York, Ontario and Québec.

All of the five NPCC subregions meet the NPCC adequacy criterion of disconnecting firm load due to resource deficiencies no more than 0.1 day per year on average. Québec, over the last three years of the assessment has a resource deficiency of up to 1,200 MW due to the 0% capacity factor used in this assessment for its wind capacity. By the end of the study period 4,000 MW of wind capacity will have been placed in service in Québec. The use of a 30% capacity factor in this assessment and in the next assessments (as ongoing studies are pointing to) would line up Québec Reserve Margin Levels with the Target Margin Level.

In all five areas, lowered economic expectations together with aggressive energy efficiency programs have essentially leveled or reduced the anticipated growth in demand for the ten-year study period. The impact of the economic recession and the increased efforts at energy efficiency can be seen in the comparisons of 2008 to 2009 load growth:

Table NPCC 1: Average Annual Load Growth Projection

	2009	2008
Maritimes	0.40%	0.90%
New England	1.20%	1.20%
New York	0.68%	0.94%
Ontario	-0.70%	-0.90%
Québec	1.04%	0.80%

Québec is targeting 11.0 TWh in recurring energy savings by 2015. Québec's Regional Reliability Self-Assessment is in the *Québec Interconnection* section of this report.

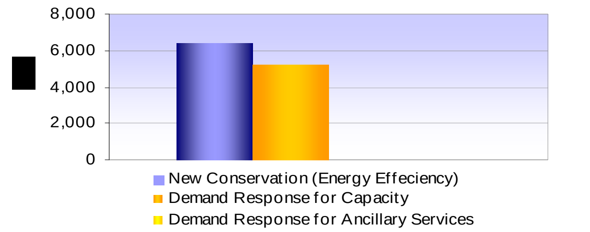
Ontario is progressing towards the elimination of all coal-fired generation by the end of 2014. The 1,250 MW Outaouais back-to-back HVdc interconnection, the double circuit Bruce to Milton 500 kV line, and 500 kV transmissions lines from Sudbury to Toronto and Sudbury to Mississagi are to be planned over the study period.

NPCC

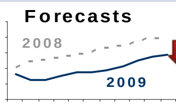
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	109,798	115,849
Direct Control Load Management	0	0
Contractually Interruptible (Curtailable)	445	433
Critical Peak-Pricing with Control	0	0
Load as a Capacity Resource	5,091	4,792
Net Internal Demand (MW)	109,134	115,197

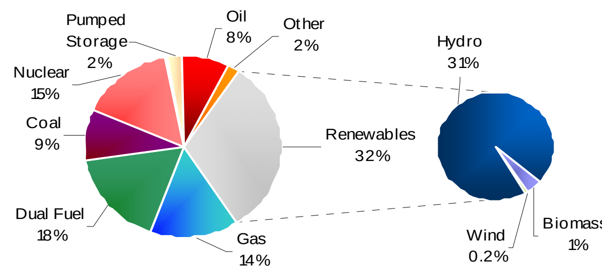
Demand-Side Management - 2018



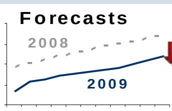
Energy Consumption	2009	2017
Net Energy to Load (GWh)	654,567	684,538
Percentage Change from 2008 Forecast	-3.2%	-3.2%



Relative Capacity Mix by Fuel Type - 2009



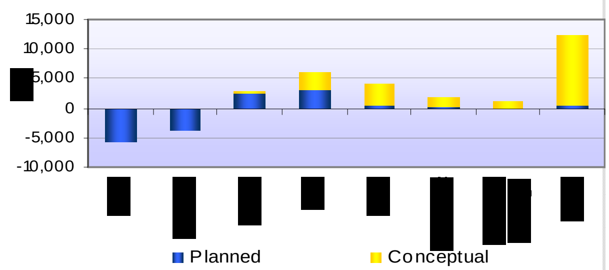
Peak Demand Comparison	2009	2017
2008 Demand Forecast	113,810	119,954
Percentage Change from 2008 Forecast	-3.5%	-4.1%



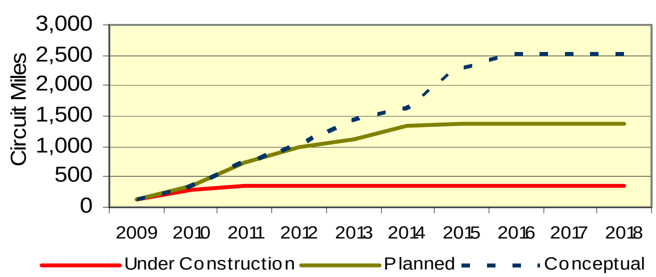
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	138,756	27.1%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	143,241	24.3%
Prospective Capacity Resources	142,964	24.1%
Adjusted Potential Capacity Resources	143,321	24.4%
Total Potential Capacity Resources	164,915	43.2%
NERC Reference Margin Level	-	15.0%

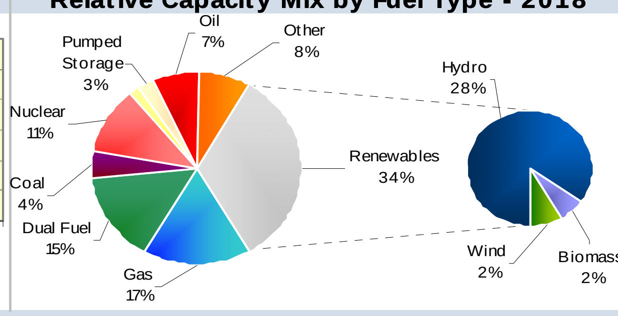
Projected On-Peak Fuel-Mix 10 Year Change



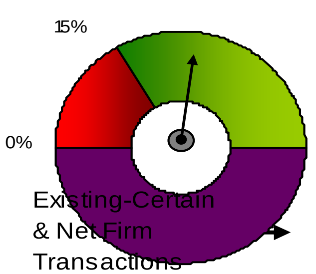
Projected Transmission Additions



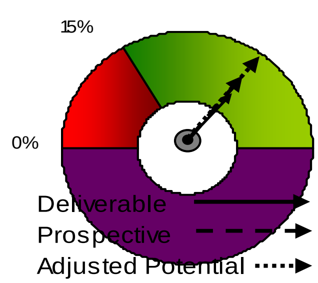
Relative Capacity Mix by Fuel Type - 2018



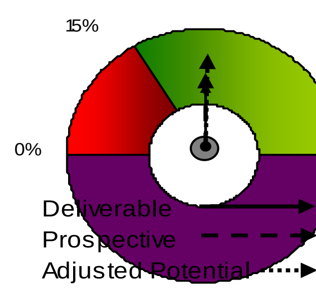
2009 Reserve Margin



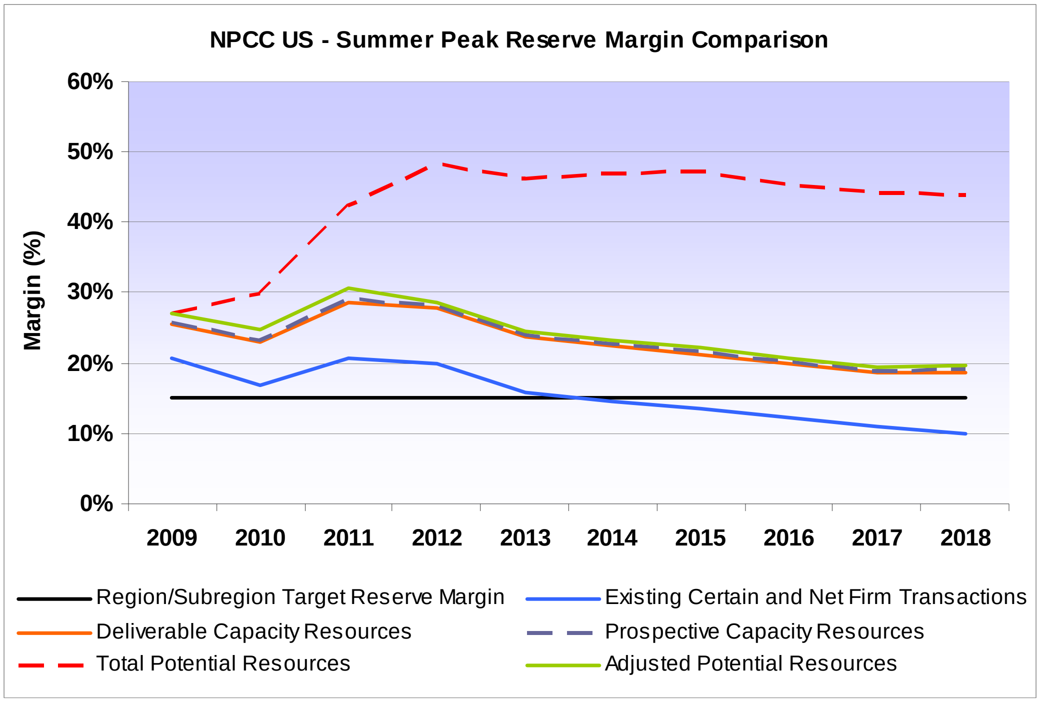
2013 Reserve Margins



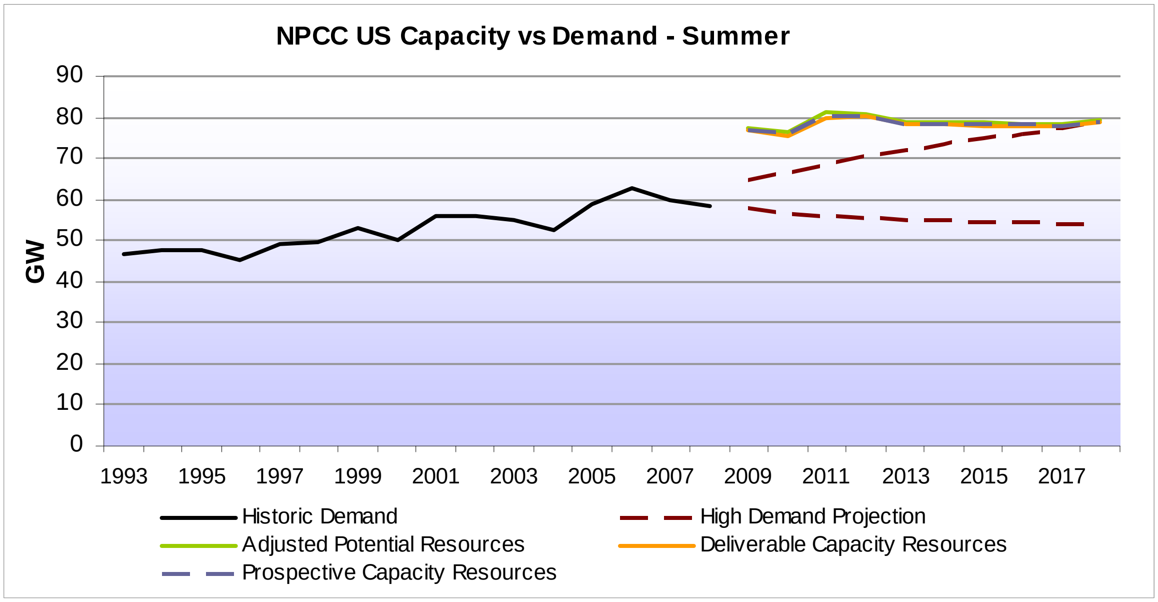
2018 Reserve Margins



For the 2009 to 2018 assessment period, NPCC-US Reserve Margins are projected to fall below the NERC Reference Margin Level by 2014 if no new resources are added. With the addition of Future resources, reserve margins should remain above the NERC Reference Margin Level.

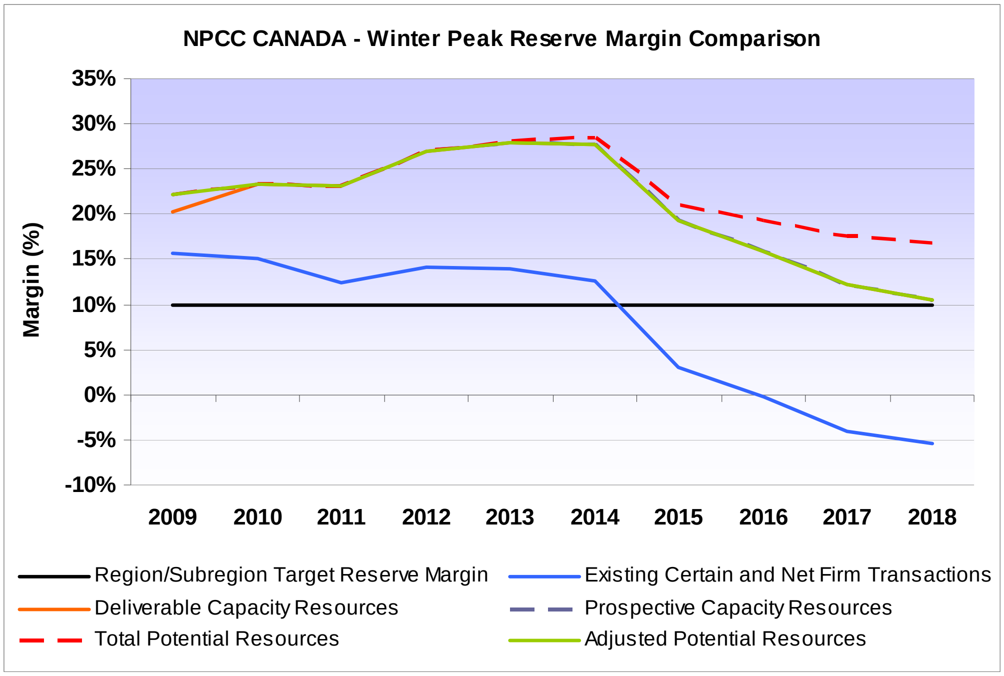


For the high demand projection[116], NPCC-US capacity resources appear sufficient to meet the NERC Reference Margin Level during the assessment period when considering all categories of capacity resources.

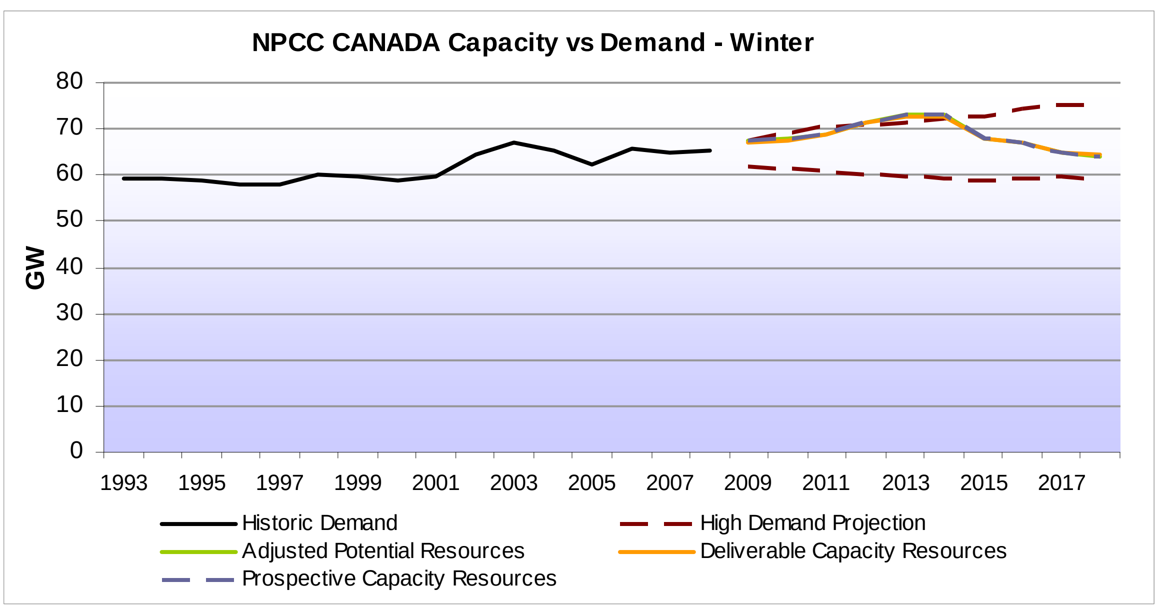


[116] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

For the 2009 to 2018 assessment period, NPCC-CANADA Reserve Margins are projected below the NERC Reference Margin Level by 2015 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.

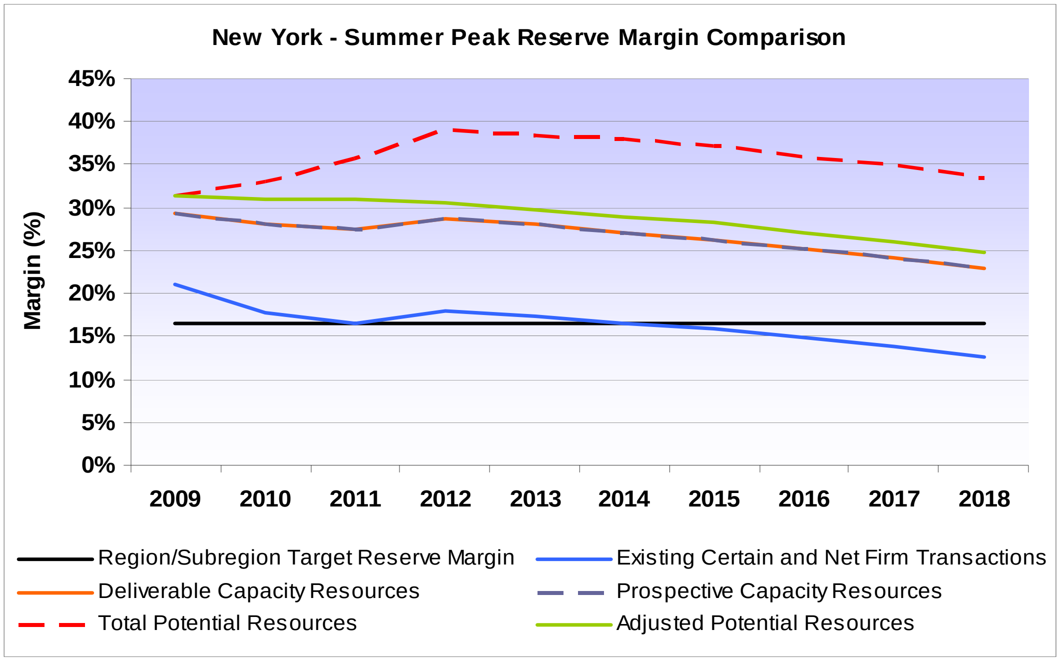


For the high demand projection[117], NPCC-CANADA capacity resources, with all categories considered, are projected to be below the NERC Reference Margin Level through the 2010 to 2018 assessment period. Between 2014 to 2018, reserve margins are further exacerbated as capacity resources are significantly reduced.

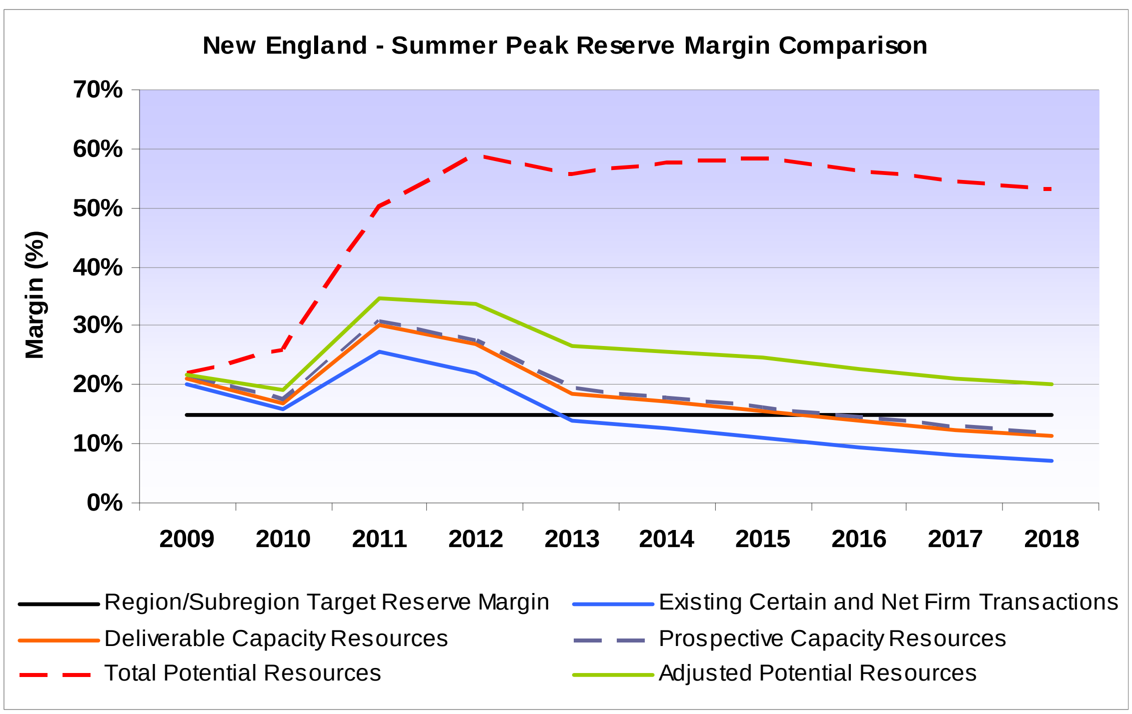


[117] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

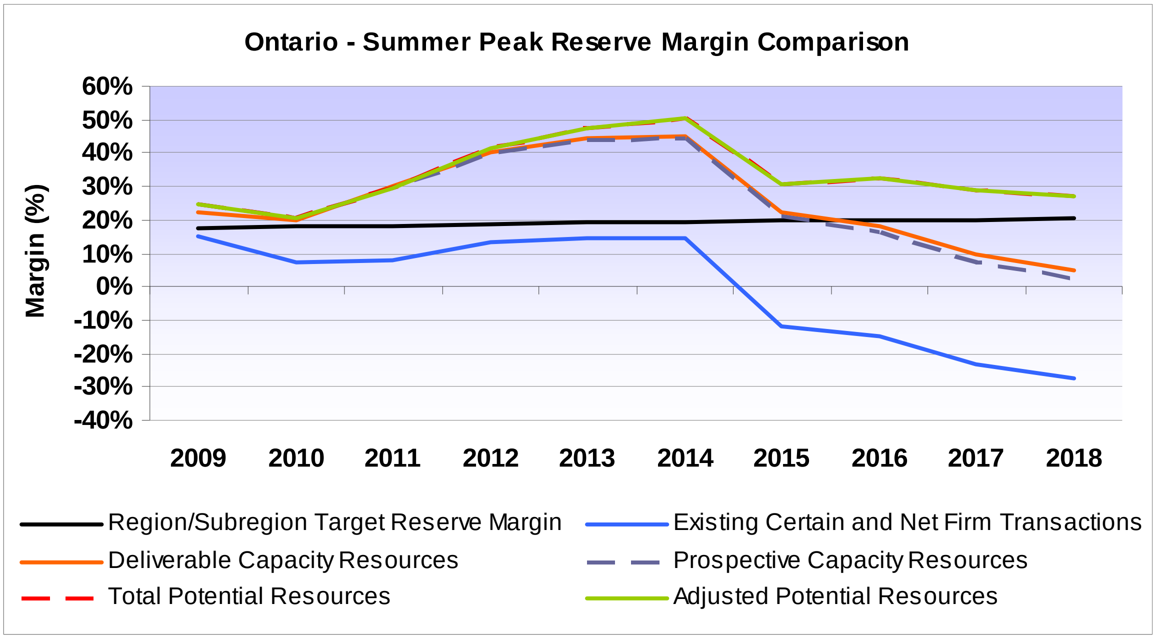
For the 2009 to 2018 assessment period, NPCC-New York Reserve Margins are projected below the NERC Reference Margin Level by 2015 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.



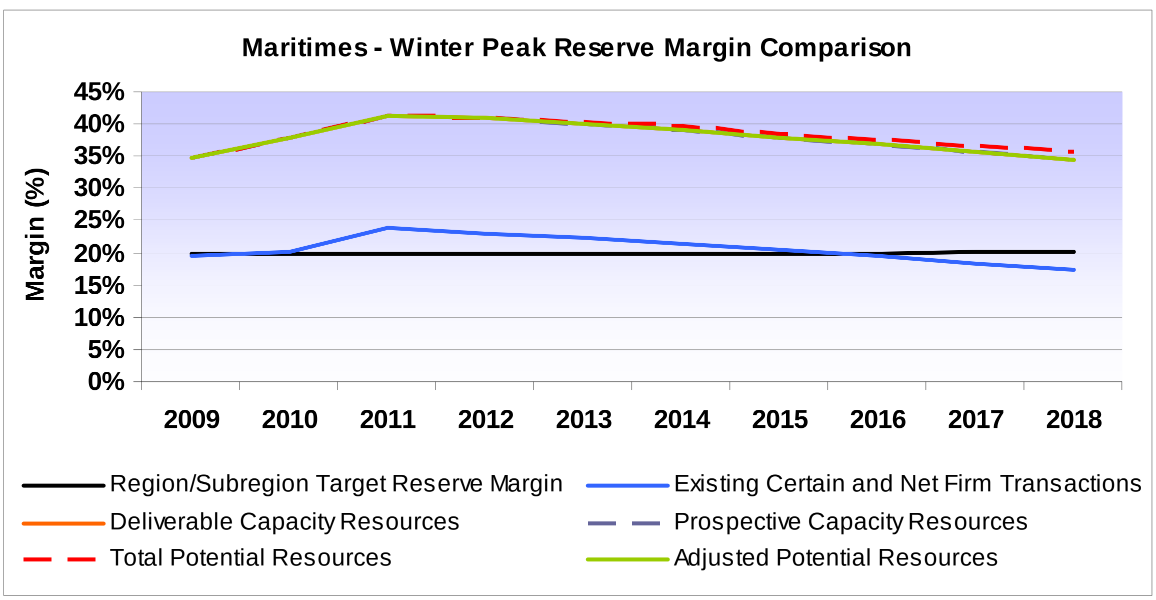
For the 2009 to 2018 assessment period, NPCC-New England Reserve Margins are projected below the NERC Reference Margin Level by 2013 if no new resources are added. Even with the addition of Future resources, a drop below the NERC Reference Margin Level is projected by 2016. NPCC-New England may need the additional resources to remain above the NERC Reference Margin Level through 2018.



For the 2009 to 2018 assessment period, NPCC-Ontario Reserve Margins are below the NERC Reference Margin Level for 2009. However, with Planned capacity additions, Reserve Margins are projected to remain above the NERC Reference Margin Level through 2016. NPCC-Ontario may need the additional resources to maintain reserves through 2018.



For the 2009 to 2018 assessment period, NPCC-Maritimes Reserve Margins are below the NERC Reference Margin Level for 2009. However, by 2010, Reserve Margins are projected to remain above the NERC Reference Margin Level through 2016 without additional capacity resources. NPCC-Maritimes may need the additional resources to maintain reserves through 2018.



Québec Interconnection Highlights

Québec is a subregion of NPCC.

The Québec Balancing Authority Area's NERC 2009 *Long-Term Reliability Assessment* Reference Case is identical to the Scenario Case (for the NERC *2009 Scenario Reliability Assessment*, a report that accompanies this report)[118] with renewable resources integration. This is because all future resources to be placed in service are renewable (Hydro, Wind and Biomass Power).

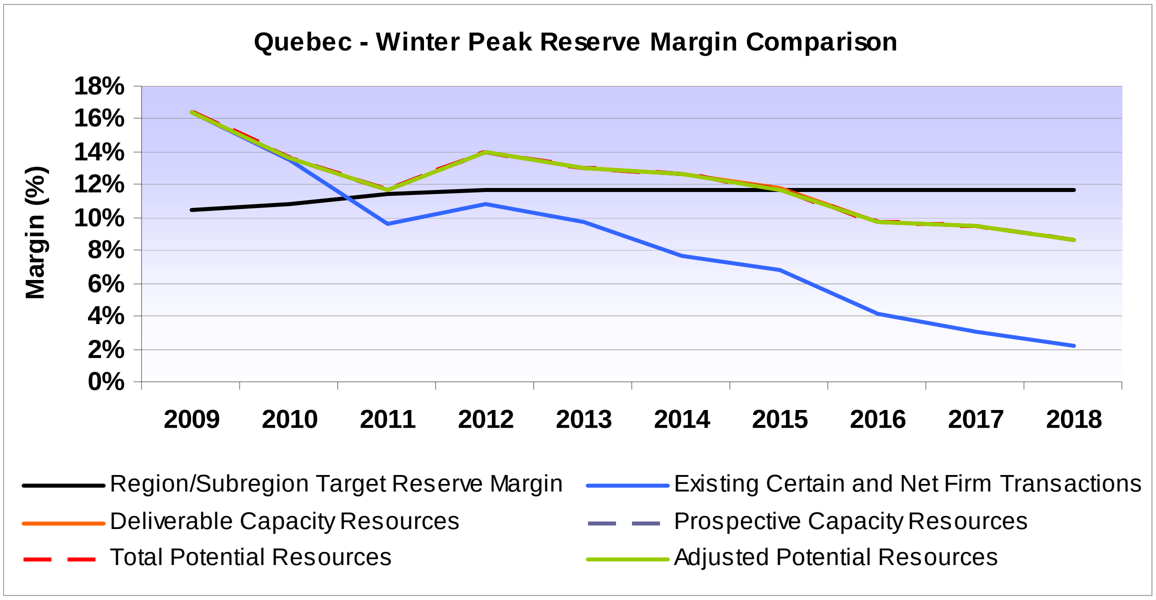
Hydro-Québec is the main generator, transmission provider and load-serving entity in Québec. Its only shareholder is the Québec government. It mostly uses renewable generating options ─ particularly hydropower ─ and supports wind energy development as a logical complement to hydro power through purchases from independent power producers in Québec. Hydro-Québec has an interest in other renewable sources such as biomass, geothermal and solar energy. HQ also contributes to research on new generating options such as hydrokinetic power, salinity gradient power and deep geothermal energy. It also conducts research in energy-related fields such as energy efficiency.

Hydro-Québec is one of the largest power producers in North America. Hydro power represents close to 94 percent of total generation. Basically, hydroelectric projects must meet three criteria before they can proceed: they must be profitable, environmentally acceptable and favourably received by the host communities.

For the 2009 to 2018 assessment period, NPCC-Québec Reserve Margins are projected below the NERC Reference Margin Level in 2011. At that time the Gentilly-2 Nuclear Generating Station will be on extended maintenance outage in 2011 to mid-2012. After that period, Reserve Margin Levels will be adequate. In this assessment NPCC-Québec may need additional resources to maintain reserves through 2015. However, even with all Conceptual resources, NPCC-Québec is projected to remain below the NERC Target Margin Level from 2016-2018. However, at that time, close to 4,000 MW of wind capacity will have been installed on the system. This capacity is derated to zero in this assessment. The use of a 30 percent capacity factor in this assessment (studies are presently ongoing to determine such a capacity factor) would represent a 1,200 MW peak capacity and would line up reserve margins with the Target Margin Level.

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

For the 2009 to 2018 assessment period, NPCC-Québec Reserve Margins are projected to be below the NERC Reference Margin Level in 2011. NPCC-Québec may need the additional resources to maintain reserves through 2015. However, even with all Conceptual resources, NPCC-Québec is projected to remain below the NERC Target Margin Level inadequate from 2016-2018.



Regional Reliability Self-Assessments

Texas Interconnection

ERCOT

Introduction

This year's long-term assessment for resource adequacy within the ERCOT Region has improved over last year's outlook. The annual Reserve Margin for the Region does not drop below the minimum target level of 12.5 percent until 2016, due to additional generating units that have gone into service or have signed interconnection agreements and a lower expectation of load growth in the early years of the assessment due to the current economic recession. There are significant amounts of additional generation that are being considered for addition in the Region, but have not yet been developed to the point of meeting the criteria for inclusion in this Reserve Margin calculation.

The number of planned transmission circuit miles and autotransformer additions over the first five years has increased since last year's long term assessment, primarily due to the inclusion of the new lines that have been ordered by the Public Utility Commission of Texas to complete its Competitive Renewable Energy Zones (CREZs). The increase in wind generation is expected to result in congestion on multiple constraints until the new CREZ transmission lines are added between West Texas and the rest of the ERCOT system. From an operational perspective, the increasing reliance on wind generation is expected to increase operating challenges. Several initiatives have been undertaken, and others continue to be under development, to ensure the appropriate procedures and requirements are in place to meet these challenges.

Demand

The 2009 long-term demand forecast for the ERCOT Region from 2009 to 2018 is lower in comparison to last year's forecast for 2008 to 2017 in each year of the forecast period. This reduction in the forecasted system peak demands is due to the economic recession reflected in the forecasted economic assumptions upon which the forecast is based. The ten-year compounded annual growth rate for the system peak, from 2008 to 2017, in last year's forecast was 1.83 percent and the ten-year system peak growth rate for 2009 to 2018 in this year's forecast is 2.04 percent. The higher ten-year growth rate in this year's forecast is fueled by the projected strong recovery from the current economic recession reflected in the economic forecast after 2010.

The peak demand forecast for this summer-peaking Region is based on the economic indicators that have been found to drive electricity use in the ERCOT Region's eight weather zones. The economic factors which drive the 2009 ERCOT Long-Term Hourly Demand Forecast[119] include per capita income, population, gross domestic product (GDP), and various employment measures that include non-farm employment and total employment. These economic indicators and variables included in the ERCOT weather zone models are designed to reflect the impacts of these major drivers for peak demand and energy use.

The forecasted peak demands are produced by the ERCOT ISO for the ERCOT Region, which is a single Balancing Authority area, based on the Region-wide actual demands. The actual demands used for forecasting purposes are coincident hourly values across the ERCOT Region. The data used in the forecast is by weather zones. The weather assumptions on which the forecasts are based represent an average weather profile (50/50). An average weather profile is calculated for each of the eight weather zones in the ERCOT grid, which are used in developing the forecast. To assess the impact of weather variability on the peak demand for ERCOT, alternative weather scenarios are used to develop extreme weather load forecasts. 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 thirteen 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 5.0 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[120] mandates that 20 percent of annual growth in electricity demand for residential and commercial customers of transmission and distribution service providers (TDSPs) in areas with full retail competition shall be met through energy efficiency programs. The TDSPs 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-use 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.

---

[119] http://www.ercot.com/content/news/presentations/2009/2009_ERCOT_Planning_Long-Term_Hourly_Demand_Energy_Forecast.pdf

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

Loads acting as a Resource (LaaRs) providing Responsive Reserve Service provide an average of approximately 1,115 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 also represents contractually committed interruptible load. EILS is not considered an offset to net demand and does not contribute to the Reserve Margin. Based on average EILS commitments during 2008, approximately 217 MW of EILS Load can be counted upon during summer peaks.

Generation

ERCOT has 71,852 MW of Existing Certain generation, approximately 8,012 MW of Existing Other generation, and 7,317 MW of Future Planned capacity slated to go into service by 2013. Conceptual capacity[121] ranges from 8,841 MW in 2010 to 27,220 MW in 2014. Existing Inoperable capacity of 7,248 MW is comprised of mothballed units as well as that portion of private networks that are unavailable for dispatch into ERCOT.

ERCOT has existing wind generation nameplate capacity totaling 8,135 MW and that capacity is expected to increase to 10,560 MW by 2013; however, only 8.7 percent of the wind generation nameplate capacity is included in the Existing Certain amount used for margin calculations, based on a study of the effective load-carrying capability (ELCC)[122] of wind generation in the Region. Consequently, the expected on-peak capacity of these resources will range from a current value of 708 MW to 919 MW by 2013. The remaining existing wind capacity amount is included in the Uncertain generation amount. Of the Existing Certain amount, 53 MW is biomass, and 45 MW additional biomass is included in the Future Planned capacity.

Before a new power project is included in Reserve Margin calculations[123], a binding interconnection agreement must exist between the resource owner and the transmission service provider. Additionally, thermal units must have an air permit issued from the appropriate state and federal agencies specifying the conditions for operation. Future capacity that will ultimately be available for the bulk of the assessment period includes 3,676 MW of gas fired generation, 3,385 MW from coal, 45 MW of biomass (wood waste), and 2,425 MW from wind turbines. Of that 2,425 MW, 211 MW (8.7 percent) contributes to margin calculations.

Purchases and Sales on Peak

ERCOT is a separate interconnection with only asynchronous ties to SPP and Mexico's Comision Federal de Electricidad (CFE) and does not share reserves with other Regions. There are two asynchronous (dc) ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability. ERCOT does not rely on external resources to meet demand under normal

---

[121] Conceptual capacity includes new generation that has requested a full interconnection study, with wind generation counted at the ELCC; generation that has only requested an initial screening study is not included.

[122] http://www.ercot.com/content/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin - Analysis_Report.pdf

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

operating conditions; however, under emergency support agreements with CFE and AEP (the Balancing Authority on the SPP side of the SPP dc ties), it may request external resources for emergency services over the asynchronous ties or through block load transfers.

For the assessment period, ERCOT has 456 MW of imports from SPP and 140 MW from CFE. Of the imports from SPP, 46 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.

SPP members' ownership stakes of 247 MW of a power plant located in ERCOT results in an export from ERCOT to SPP of that amount.

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

There are no non-Firm contracts signed or pending over any of the ties. There are also no other known contracts under negotiation or study using the asynchronous ties.

Transmission

The Public Utility Commission of Texas (PUCT) completed its Competitive Renewable Energy Zone (CREZ) process in 2008, resulting in additional planned bulk transmission in West Texas to provide solutions to existing and potential congestion and enable the installation of more renewable generation in West Texas. The CREZ lines are expected to be in service in the 2012 to 2013 timeframe.

New 345 kV lines are under construction from Clear Springs-Hutto-Salado and from San Miguel to Laredo, as well as several projects in the Dallas/Fort Worth area, to support reliability in these Regions. There are no concerns in meeting target in-service dates of the transmission projects, but operational procedures to maintain reliability will be implemented if unforeseen delays occur in these or other planned projects.

Longer term, load growth in the Houston area, the central Texas area, and in the lower Rio Grande Valley is likely to require additional transmission capacity into those areas during years six through ten.

Operational Issues (Known or Emerging)

No major facility outages, environmental or regulatory restrictions, water level or temperature issues, or temporary operating measures that would significantly impact reliable operations over the ten-year assessment period.

ERCOT should have sufficient capacity even for a peak demand that is as high as the 90th percentile of the weather sensitivity in the load forecast, which could result in a peak demand 5.3 percent higher than the expected peak demand. An extremely hot summer that results in load levels significantly above forecast, higher than normal unit forced outage rates, or 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 plan (EEA) (See Section 5.6.6.1 of the ERCOT Protocols)[124]. The EEA plan includes procedures for use of interruptible load, voltage reductions, and procuring emergency energy over the dc ties. ISO-instructed Demand Response procedures are in place and are described in the ERCOT Operating Guides Section 4.5. [125]

Reserve margins will likely be at minimum levels over the assessment period. This, coupled with resource vulnerability to winter gas curtailments, could increase the likelihood that operators will need to initiate emergency procedures such as the EEA in the future.

The continued increase in installed wind generation has the potential to lead to increased operating challenges. A Renewable Technologies Working Group (RTWG) has been formed to focus on 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 and is reporting to the Public Utility Commission of Texas on a quarterly basis[126].

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 required amounts of 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 better reflect the sensitivities of zonal control actions upon the expected congested transmission elements due to increased wind penetration.

The major market redesign approved by the PUCT will change current congestion management procedures from a zonal to a nodal-based system. This transition, which will occur during the assessment period, should improve the efficiency of transmission congestion management and provides a five-minute market dispatch, which should improve the amount of regulation service needed due to additional wind resources.

ERCOT plans to perform a study during the next year of the impact of distributed intermittent resources and the impact of the large-scale implementation of advanced metering and related implementations of new technology that may affect the use of the transmission system from the

[124] http://www.ercot.com/mktrules/protocols/current.html
[125] http://www.ercot.com/mktrules/guides/operating/current.html.
[126] 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

load side. Significant penetration of distributed resources is not expected to occur on a timescale that would preclude timely system and procedural changes and result in reliability concerns.

Reliability Assessment Analysis

ERCOT has an adequate Reserve Margin through 2015 but the Reserve Margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2016, based on new generation with signed interconnection agreements and existing resources. The minimum Reserve Margin target of 12.5 percent is applied to each year of the ten year assessment period and is based on a Loss-of-Load Expectation (LOLE) analysis[127], resulting in no more than one-day-in-ten years loss of load.

ERCOT almost entirely uses internal resources to serve its load and reserves, with the exception of a 46 MW purchase from SPP and emergency support agreements with SPP and CFE. ERCOT has 71,852 MW of installed generation (summer), with additional signed interconnection agreements for 7,061 MW of new fossil fuel generation and 211 MW of wind generation over the next ten years.

Reserve margins for the Region have improved since last year's assessment due to the lower demand forecast and several additional wind and gas-fired generating units that have signed interconnection agreements.

Only 8.7 percent of existing wind generation nameplate capacity is counted on for Certain generation, based on an analysis of the effective load-carrying capability of wind generation in the Region.[128] The remaining existing wind capacity amount is included in the Uncertain generation amount.

ERCOT currently has a reliability must-run (RMR) agreement with one generator that was scheduled to retire by its owner but was needed to maintain transmission system reliability. Another unit at the same plant is scheduled for retirement this fall and will be required for RMR service as well. Transmission projects to relieve this need are scheduled. There are no other currently known unit retirements, which have significant impact on reliability.

ERCOT does not have a formal definition of generation deliverability. However, in the planning horizon, ERCOT 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 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 as the balancing authority and reliability coordinator. Operational resource adequacy is also maintained by ERCOT through market-based procurement processes (See Sections six and seven of the ERCOT Protocols[129]).

---

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

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

[129] http://www.ercot.com/mktrules/protocols/current.html

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. This is not expected to limit deliverability during peak periods, since only 8.7 percent of the installed wind capacity is counted for reserve purposes.

The PUCT has ordered the construction of approximately $5 billion in transmission system upgrades as a part of the Competitive Renewable Energy Zone (CREZ) process[130]. This transmission is intended to enable wind generation in West Texas to be able to serve load in the rest of the ERCOT Region and is expected to be completed by the end of 2013.

ERCOT has interconnections through dc ties with the Eastern Interconnection 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 identify any import/export limits.

Under-Voltage Load Shed (UVLS) schemes are deployed in the following areas: Houston ~ 4,500 MW, DFW ~ 3,500 MW, and the Rio Grande Valley ~ 650 MW. Additional UVLS deployments in other areas have been considered, but at this time there are no implementation plans. The Houston and DFW deployments are intended to provide a "safety net" and are not targeted to specific events. UVLS are not generally relied upon to survive NERC Category B and C events and system reinforcements may be made to limit the amount of load shed that is necessary under certain extreme contingencies (NERC Category D events). The Rio Grande Valley deployment is intended to prevent (local) voltage collapse that may result following certain Category C contingencies.

ERCOT is not generally reliant on single gas pipelines or import paths such that the long term outage of one of these systems would lead to loss of significant amounts of generating capacity. ERCOT is not prone to earthquakes or other widespread catastrophic events that would lead to resource adequacy concerns except for hurricanes. However, these storms do not generally result in a resource adequacy concern. The ERCOT Region does not have a specific drought response plan.

Individual transmission owners have their own guidelines for spare autotransformers and may participate in sharing programs, but there are no Regional guidelines for spare generator, step-up transformers, or autotransformers.

ERCOT performs studies in the operations planning horizon and may develop Remedial Action Plans or Mitigation Plans 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

---

[130] http://www.ercot.com/content/news/presentations/2008/ERCOT_Website_Posting.zip - Scenario 2, p. 24ff

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 Interconnection.

No explicit minimum dynamic reactive criteria exist, however reactive margins are maintained in the major metropolitan areas. Areas of dynamic and static reactive power limitations are Corpus Christi, Houston, Dallas/Ft. Worth, Rio Grande Valley, South to Houston generation, South to Houston load, North to Houston Generation and North to Houston load. Operating Procedure 2.4.3 VSAT (Voltage Stability Analysis Tool) describes the procedure to monitor the system and to prevent voltage collapse using the online voltage stability analysis tool. Different scenarios along with the MW safety margins are described and mitigation procedures are prescribed based on VSAT results. Once the prescribed action is communicated, taken, and verified, VSAT will be rerun with the new topology.

ERCOT plans for a 5 percent voltage stability margin for Category A and Category B contingencies and a 2.5 percent margin for Category C contingencies[131]. ERCOT planning criteria are intended to maintain sufficient dynamic reactive capability to maintain system voltages within the range for which generators are expected to remain online.

Utilities in ERCOT are making significant investments in Smart Grid technologies. An estimated one million advanced meters will be installed by the end of 2009, rising to over six million[132] by the end of 2013 as a result of the PUCT's Advanced Metering implementation project. In addition, several flow-control devices have been added to the system (such as phase-shifting transformers and switchable series reactors) to mitigate transmission constraints and improve system efficiency.

Aging infrastructure is not expected to result in significant reliability impacts. Many of the older gas-fired generating units in the ERCOT Region have been mothballed or retired; the capacity-weighted age of the Existing Certain generation in ERCOT is 22.5 years. Although some generation developers have expressed concerns related to obtaining financing for their planned generation in the near term, ERCOT has not been notified of significant cancellations or delays.

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 with a population of about 22 million covering approximately 200,000 square miles. ERCOT is 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.

---

[131] http://www.ercot.com/mktrules/guides/operating/2007/07/05/05-070107.doc

[132] This does not include advanced meter deployments planned by AEP, Texas-New Mexico Power; there are also some deployments by the municipal and co-op utilities

There are 216 Registered Entities, with 334 functions (as of 5/15/2009), operating within the ERCOT Region. Within the ERCOT 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.[133]

[133] http://www.ercot.com

Western Interconnection

WECC

Introduction

WECC loads are growing at a lower rate than reported in 2008 — the projected 2009 summer total internal demand of 160,688 MW is expected to increase by 1.8 percent per year to 188,030 MW in 2018.

The planning Reserve Margins used for this report were developed using a building block method. The planning Reserve Margins will be referred to as target margins in this assessment. These target margins range between 10.1 and 22.3 percent, with an overall average of 17.2 percent in summer and 16.1 percent in winter.

Reserve margins in all of WECC's subregions have improved due to decreased load growth, adverse economic conditions, increased generation capacities, and demand-side-management programs.

Using the NERC definitions of future resources, WECC assumes that all of the Future Planned[134] (FP) resources will be constructed and that both the potential, Future, Other[134], (FO) and Conceptual[134] resource additions should be adjusted by confidence factors to determine the expected adjusted potential resource additions. The contribution toward the summer peak from the Existing Certain[134] (EC), FP, FO, and Conceptual resources are summarized in the following table:

*Existing Resources	Future Planned Resources	Potential Future Other Resources	Potential Conceptual Resources	*Adjusted Future Other Resources	*Adjusted Conceptual Resources
**201,002	37,708	53	13,196	0	7,772
197,568	37,708	Potential = 13,249 MW		Adj. Potential = 7,772 MW	

* The 2018 confidence factors for the Region were 0 and 59 percent for the FO and Conceptual resources.
** Value for July 2009 and includes 3,434 MW that is scheduled for maintenance.

WECC is comprised of four general subregions: the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA), the Arizona–New Mexico–Southern Nevada area (AZ-NM-SN), and the California–Mexico area (CAMX). The NWPP subregion includes portions of the U.S. (NWUS) and Canada (NWCN). The CAMX subregion includes portions of the U.S. (CMUS) and Mexico (CMMX).

Inter-subregional transfers were derived from the Supply Adequacy Model (SAM) runs. In SAM, conservative transmission limits were placed on paths between the 26 load groupings

[134] This is a NERC definition – See *Terms Used in This Report*

(bubbles) when calculating the transfers between these areas. These load bubbles were developed for WECC's Power Supply Adequacy (PSA) studies. The aggregation of PSA load bubbles into WECC subregions may obscure differences in adequacy or deliverability between bubbles within the subregion. These transfers were submitted to NERC as Firm and Expected[134] transactions depending upon the inclusion of future planned resources.

In the Table of Reserve Margins (below), the Net Capacity Resources (NCR) line includes the expected transfers and the peak values of the existing and FP resources. The Adjusted Potential Resources (APR) line includes the NCR values and the adjusted potential resources.

TABLE OF RESERVE MARGINS									
	WECC	*NWPP	*NWUS	*NWCN	RMPA	AZ-NM-SN	CAMX	CMUS	CMMX
Target Margin	17.2%	16.6%	18.4%	13.2%	17.1%	17.8%	22.1%	22.3%	15.6%
2009									
NCR Margin	27.6%	28.9%	37.0%	13.8%	23.6%	17.5%	22.1%	22.3%	15.7%
APR Margin	27.6%	28.9%	37.0%	13.8%	23.6%	17.5%	22.1%	22.3%	15.7%
2018									
NCR Margin	23.3%	14.1%	22.2%	-0.7%	17.3%	17.4%	26.6%	27.5%	5.2%
APR Margin	33.8%	20.2%	23.2%	14.8%	25.4%	21.4%	44.7%	45.0%	37.8%
*Reflects the winter Reserve Margins for winter-peaking subregions.									

When considering only the net capacity resources, the Canadian portion of the Northwest Power Pool subregion (NWCN) goes below the WECC-developed target margin for that subregion, as early as the winter of 2011/2012. When also considering the adjusted potential of both the FO and Conceptual resources, the NWCN Reserve Margin remains above the target margin.

In the CMMX subregion, when using the net capacity resources, the Reserve Margin is projected to be above the target margin through 2014. When including the adjusted potential of the FO and Conceptual resources, the CMMX subregion would remain above their target margin throughout the assessment period.

By the summer of 2018, the difference between WECC's net capacity resources (234,561 MW) and WECC's Total Internal Demand (188,030 MW) will be 46,531 MW (24.7 percent Reserve Margin). This would be 31,114 MW above the desired target margin. This included serving 6,950 MW of Demand-Side-Management (DSM) load. If the DSM load were not to be served it would result in a 23.3 percent Reserve Margin, which is reflected in the above table of Reserve Margins.

When looking at subregions, or a Region overall, it may be questionable to only consider the Net Internal Demand (total internal demand minus DSM programs) when calculating margins. The question arises from how DSM programs are treated and if they are sharable or not between Load Serving Entities (LSEs), Balancing Authorities (BAs), subregions, or Regions. Some DSM programs have a limited number of times they can be called upon and some can only be called upon during a declared emergency and not for other areas. If the programs are not sharable, then the Reserve Margin should be calculated using the total internal demand and not the net internal demand.

Neither the summer nor the winter analysis for the Northwest subregion fully captures the limitations on the ability of the energy-constrained Northwest hydro system to sustain output levels beyond a single hour.

This self-assessment is based on loads and resources data submitted to WECC in February.

Peak Demand

Total summer internal demand decreased by 2.3 percent from 2007 to 2008. Summer temperatures in 2007 were normal to somewhat above normal while summer temperatures in 2008 were generally normal to somewhat below normal. The projected aggregate of 2009 and 2018 summer total internal demand forecasts and the growth rates can be seen in the table below. The summer total internal demand is expected to increase by about 1.8 percent per year for the 2009 to 2018 timeframe which is lower than the 2.0 percent projected last year for the 2008 to 2017 period.

Summer Peaking Demands (MW)				
	WECC	WECC US	WECC CN	WECC MX
2008 Actual	154,255	134,829	17,389	2,037
2009 Projected	160,688	140,692	18,071	2,115
Growth	4.2%	4.3%	3.9%	3.8%
2018 Projected	188,030	163,412	22,006	2,612
2009 – 2018 Growth	1.8%	1.7%	2.2%	2.4%

Annual Energy Use (GWh)				
	WECC	WECC US	WECC CN	WECC MX
2008 Actual	889,670	745,691	132,659	11,320
2009 Projected	885,460	738,416	136,357	10,687
Growth	-0.5%	-1.0%	2.8%	-5.6%
2018 Projected	1,034,920	851,808	170,339	12,773
2009 – 2018 Growth	1.7%	1.6%	2.5%	2.0%

WECC specifically directs its BAs to submit forecasts with a one-year-in-two (50/50) probability of occurrence. Most entities based their forecasts on population growth, economic conditions, and normalized weather. WECC has not established a quantitative analysis process for assessing the variability in projected demands due to the economy, but most of the forecast submissions took into consideration the current economic recession. Some of the BAs in California used the most recent forecast developed by the California Energy Commission (CEC). The CEC forecast, when the data was submitted to WECC, was developed in late 2007 and did not reflect the impact of the recession.

WECC staff does not perform independent load forecasts. The internal peak demand forecasts presented here are a non-coincident sum of the forecasted demands submitted by WECC's 36 BAs. Some BAs plan on meeting a non-coincidental peak of their balancing area, while others plan on meeting a coincidental peak. BAs that have a large amount of load diversity within their area, or receive non-coincident forecasts, may apply a coincidence factor to better determine a coincident demand. This coincidence factor is derived from the analysis of historic hourly loads for the areas. Comparisons with hourly demand data indicate that WECC non-coincident peak demands generally exceed coincident peak demands by two to four percent.

Energy efficiency programs vary by location and are generally offered and administered 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.

Within the WECC Region, there is a mixture of demand response programs. Demand response programs usually fall into two categories: 1) Passive DSM programs, and 2) Active DSM programs. A key difference between the categories lies in whether the program is controllable or dispatchable by the LSE or BA. Passive DSM programs are not dispatchable and largely consist of energy efficiency programs. Active DSM programs are dispatchable and include direct load control, interruptible tariffs, and demand bidding programs. The review, measurement, and verification of the DSM programs are the responsibility of the individual BA or LSE and some entities present their results to their State public utilities commissions. As with the energy efficiency programs, some entities retain independent third parties to evaluate their programs.

The total WECC internal demand forecast includes Demand Response and interruptible loads that increase from 4,290 MW in 2009 to 6,950 MW in 2018. The direct control demand-side management capability is located mostly in California (2,816 MW in 2009 and 4,767 MW in 2018), but DSM programs in other subregions are increasing with the most prevalent Demand Response programs being air conditioner cycling programs. Interruptible load programs focus on the demand of large water pumping operations and large industrial operations such as mining.

The BAs and LSEs use various peak forecasting methods. These range from not taking into account weather or economic assumptions (due to having a statutory load obligation with zero load growth), to using a combination of the EPRI-developed Residential End-Use Energy Planning System (REEPS) and the Commercial End-Use Model (COMMEND), to forecast the commercial sector energy demands by end-use and then using an econometric method by major Standard Industrial Classification codes. Some of the BAs used linear regression techniques with a historical multi-year database to develop the winter and summer season peak forecasts.

Several of the entities use various weather scenarios (i.e., one-year-in-five, one-year-in-ten conditions) for other internal planning purposes. Econometric models used by various entities within the Western Interconnection consider things such as rate change effects, average area population income, etc.

WECC staff and the Loads and Resources Subcommittee (LRS), perform an annual Power Supply Assessment (PSA) which uses the submitted forecasts and evaluates the potential variability due to weather. The PSA uses a building block method for determining planning margins for its analysis.

Generation

The generation data for the *Long-Term Reliability Assessment* is provided by all of the balancing authorities within the Western Interconnection and is processed by WECC's staff under the direction of the LRS.

The following table reflects the WECC summer on-peak capacity for Existing Certain (EC), Future Planned (FP), Future Other (FO), and Conceptual generation resources for the assessment period.

Existing and Potential Resources (On-Peak) (Constructed through July 31, 2018)

	*Existing (MW)		FP (MW)	Potential FO (MW)	Potential Conceptual (MW)	Total New Resources 2018
Total Installed	**216,953**		**53,853**	**160**	**17,471**	**71,484**
Conventional	137,771		21,894	5	11,081	32,980
Hydro	68,651		1,639	0	1,965	3,604
Wind	8,476		14,856	100	3,456	18,412
Biomass	1,646		545	50	228	823
Solar	409		14,919	5	741	15,665
	***Existing Certain (MW)**	***Existing Other (MW)**	**Future Planned (MW)**	****Adjusted Future Other (MW)**	****Adjusted Conceptual (MW)**	**Total New Resources 2018**
Total Expected Resources	**201,002**		**37,708**	**0**	**7,772**	**45,480**
Conventional Expected	134,260		17,665	0	6,394	24,059
Hydro Expected	62,934		1,587	0	716	2,303
Wind Expected	1,753		2,948	0	92	3,040
Biomass Expected	1,646		574	0	134	708
Solar Expected	409		14,934	0	436	15,370
Derates or Maintenance		**12,850**	**38,148**	**107**	**4,226**	**42,481**
Hydro Derate		5,717	0	0	0	0
Wind Derate		6,723	11,965	0	1,943	13,908
Biomass Derate		292	40	0	0	40
Solar Derate		118	3,077	0	110	3,187
Scheduled Outages		3,434				0
Confidence Factor				**0%**	**59%**	

*The Existing Certain resources in this table represent the July 2009 values expected at the time of peak. The Existing Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.

** The Adjusted values represent the July 2018 peak values of the Future Other or Conceptual resources after confidence factors were applied.

WECC's Existing, Future and Conceptual Resource values are presented in the above table. The summer peak value for the EC resources (existing in-service as of December 31, 2008) for July 2009 is 197,568 MW. This value reflects the monthly shaping of variable generation, seasonal ratings of conventional resources, and 3,434 MW of scheduled maintenance planned during this month. The resources classified as Existing Other[135] (EO) (amount not counted towards on-peak capacity) totals 12,850 MW. The FP capacity resources projected to be in-service by the end of this assessment period is 37,708 MW. The total potential capacity and the potential on-peak capacity of FO resources, without applying the confidence factor, are 53,853 MW and 53 MW, respectively. The above table provides a breakdown of some of the resource types and their associated non-derated and derated capacities.

The FO resources, in aggregate in 2018, have a reported confidence factor (probability of installation) of zero. This confidence factor adjusts the FO on-peak capacity to zero MW.

The total potential capacity and the potential on-peak capacity of conceptual resources are 17,471 MW and 13,196 MW, respectively. The adjusted on-peak potential is 7,772 MW net after applying an aggregate confidence factor of approximately 59 percent.

The on-peak wind capacity is determined by the individual BAs using a variety of methods. Examples include assumption of zero contribution towards meeting the on-peak demand, 5 percent of the installed capacity, and calculations based on historical production data.

The analysis methods (as specified in the Long-Term Reliability Assessment instructions) used to quantify resource adequacy over the entire Western Interconnection expose three key limitations that are not accounted for in the analysis:

- Neither the summer nor the winter analysis for the Northwest subregion fully captures the limitations on the ability of the Northwest hydro system to sustain output levels beyond a single hour. Because of this limitation the reported surpluses, both to meet the northwest load and for export to other subregions, may be unrealistically high.
- Not all DSM programs are totally controllable by the BA. Some programs are controlled by the individual LSEs and could be operated without the BAs knowledge. Some programs are customer controlled with penalties for not complying with demand reduction requests by the BA.
- When calculating an area's Reserve Margin using the net internal demand (total demand minus DSM programs), when DSM programs are not sharable, may produce a higher Reserve Margin than may occur.

Margin	WECC	WECC-US	NWPP	NWPP-US	NWPP-CN	RMPA	AZ-NM-SNV	CAMX	CAMX-US	CAMX-MX
Summer Margin	17.2%	17.9%	14.8%	16.3%	11.5%	17.1%	17.8%	22.1%	22.3%	15.6%
Winter Margin	16.1%	16.7%	16.6%	18.4%	13.2%	15.4%	15.5%	15.7%	15.9%	10.1%

The planning Reserve Margins or target margins in the above table were derived using the 2009 load forecast and the same method as the 2008 PSA. The PSA uses a building block method for developing and planning Reserve Margins and has four elements: contingency reserves, operating reserves, reserves for additional forced outages, and reserves for one-year-in-ten weather events. In this year's calculations, higher operating reserve values were submitted to

[135] NERC definition – See Appendix III

help account for regulating with a larger amount of variable resources. The building block values were developed for each balancing authority and then aggregated by subregion and for the entire WECC Region. The aggregated summer season target margin for WECC is 17.2 percent. These Reserve Margins were developed specifically for use in the *Long-Term Reliability Assessment* and PSA, and may be lower or higher than some of the state, provincial, or LSE requirements within WECC. These target margins are not requirements for the WECC BAs to meet, but are only for reporting purposes.

Last year the LRS used a capacity factor of zero for the potential resources. This year the LRS requested the BAs assign an array of two confidence factors. One was applied seasonally to the sum of the FO resources and the other applied to the sum of the conceptual resources. Using the confidence factors from the BAs, Regional and subregional confidence factors were developed. These adjusted totals were used by the Supply Adequacy Model (SAM) to determine the surplus margins and resulting diversity exchanges used in this *Long-Term Reliability Assessment*. The potential values of the FO and Conceptual resources appear in the Reserve Margin charts in the "Total Potential" line but are reduced in the "Adjusted Potential" line when the confidence factors are applied.

The 36 BAs in WECC use a variety of methods to determine their future resource requirements. Many 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. Some of the processes used to quantify the need for more resources include: forward capacity markets and resource adequacy needs, obligation to serve activities, and the certainty of resources under consideration. The selections of additional resources, often includes an evaluation of fuel diversity, environmental impacts, or the need to add new generation to meet renewable portfolio standards. In addition, some entities use optimization programs to help select the best portfolio of future resources, minimize the amount of energy not served (ENS), or solve for a desired loss of load probability (LOLP). To secure the identified additional resources, many entities within WECC use formal Request for Proposals (RFPs) or rely on the market price signals to spur development of the resources.

Individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in Section III of the WECC Planning Coordinating Committee's Handbook[136]. These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to enhance deliverability and to mitigate possible adverse power system conditions.

With the increased projection of additional new resources in California, more diversity exchanges will be available for use by other subregions. The PSA does not indicate any transmission limitations for transfers from the DSWA into California. This may be due to the projected lack of excess resources in the DSWA. Because the transfers between subregions are calculated using the projected capability of wind generators at the time of peak, additional

[136] http://www.wecc.biz/committees/StandingCommittees/PCC/Shared%20Documents/PCC_Handbook_Complete.pdf

transfers from wind or other generation may be blocked by inadequate transmission capacity during other hours. The extent of these additional potential transfers is unknown and was not considered in this *Long-Term Reliability Assessment* or the PSA analysis. WECC has recently established a Variable Generation Subcommittee (parallel to NERC IVGTF) to examine issues related to planning for and operating with large amounts of variable generation on the system.

Purchases and Sales on Peak

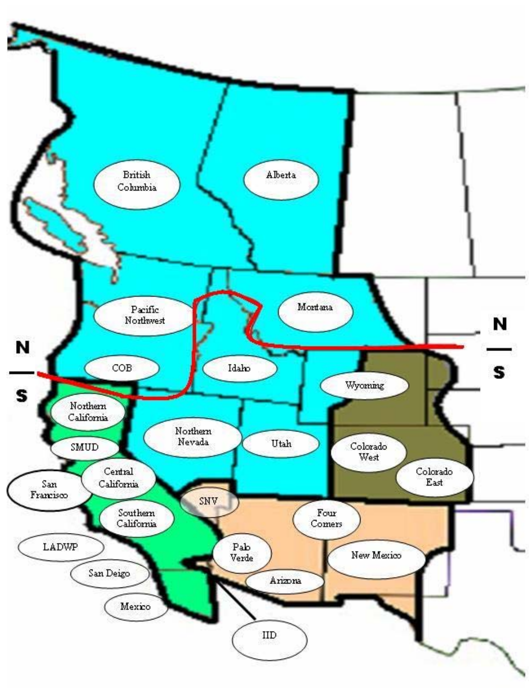
For the summer of 2009, WECC entities reported net firm on-peak imports from Eastern Interconnection entities of 262 MW. By the summer of 2018, this number is reported to decline to 103 MW. The gross imports are scheduled across three back-to-back dc ties with SPP and four of the five back-to-back dc ties with MRO. The gross exports are scheduled across the back-to-back dc ties with MRO. Expected transfers with the Eastern Interconnection represent a very small fraction of total capacity. For this self-assessment, interchanges with the Eastern Interconnection are represented as a constant 325 MW resource in the AZ-NM-SNV subregion.

The resource data for the individual subregions include transfers between subregions that are either plant contingent transfers or reflect expected economic transfers with a high probability of occurrence. The plant contingent transfers represent both joint plant ownership and plant-specific transfers (distribution of generation from facilities that have multiple owners or transfers tied to a specific generation facility) from one subregion to another.

The projected economic transfers reflect the potential use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest, as well as other economy and short-term firm purchases that are expected to be available in Western markets. Supply Adequacy Model (SAM) is a modified least-cost dispatch program. SAM, developed by the California Energy Commission, calculates transfers that are physically possible, but they do not reflect underlying contractual or other commitments.

Despite the fact that these transactions may not be contracted, they reflect a reasonable modeling expectation given the history and extensive activity of the Western markets, as well as the otherwise underused transmission from the Northwest to the other subregions. When using the adjusted potential resource mixes, all of the subregions are able to maintain adequate reserves.

A process similar to the one used to determine Regional and subregional target margins was used to determine the inter-subregional transfers using SAM. The various area bubbles used were combined into the appropriate WECC subregions (see the below diagram) and the excess or deficit capacity as reported by SAM was summed for each of the WECC subregions. The excess/deficit capacity was then used to calculate the amount of expected purchases or expected sales transactions between the various subregions.



The 2009 SAM results indicated possible congestion within some of WECC's subregions due to economic diversity exchanges. As an example, a condition called the "North-South split" traditionally occurs when the transmission ties between the California Oregon Border (COB), Pacific Northwest, British Columbia and Montana (the North), and the areas to the south are insufficient to allow all reported surpluses in the north to meet loads south of the constraint in the economic dispatch performed in SAM. In the past, the North-South split usually occurred within the NWPP subregion. With the projected resource additions and updates to the transmission system, the split sometimes drops lower into central California and the Rocky Mountain Power Area (RMPA). Utah, in all cases, was south of the North-South split.

Inter-subregion transmission interconnection power transfer capabilities, are not sufficient to accommodate all economic energy transactions at all times of the year. For example, the transmission interconnections between the northern and southern portions of the Western Interconnection are periodically fully loaded in the north-to-south direction during the summer period and may experience limitations in the opposite direction during the winter period. In addition to the inter-subregion limitations, intra-subregional transmission is not always sufficient to accommodate all economic energy transactions at all times of the year. WECC establishes seasonal operating transfer capability (OTC) limits and invokes schedule curtailments to address the near-term inter and intra-subregion transmission limitations.

Western entities participate in shorter-term power markets, for which forecasts are not available. This is a primary reason the WECC analysis uses the simulation process described above to determine the expected transfer values. The Western Systems Power Pool (WSPP) contract, which contains liquidated damage provisions, is heavily relied upon as the template for such transactions.

Fuel

WECC does not conduct a formal fuel supply interruption analysis. Historically, coal-fired plants have been built at or near their fuel source and generally have long-term fuel contracts with the mine operators, or actually own the mines. This pattern is less true for newer plants or those proposed for possible development after 2010. Gas-fired generation is typically located near major load centers and relies on relatively abundant western gas supplies. In addition, some of the older gas-fired generators in the Region have backup fuel capability and normally carry an inventory of backup fuel, but WECC does not require verification of the operability of the backup fuel systems and does not track onsite backup fuel inventories. Most of the newer generators are strictly gas-fired, which has increased the Region's exposure to interruptions to that fuel source.

A survey of major power plant operators indicates that their natural gas supplies largely come from the San Juan and Permian Basins in western Texas, gas fields in the Rocky Mountains, and from the Sedimentary Basin of Western Canada.

Dual-fuel capability is not a significant source of supplement to natural gas within the Western Interconnection. Only a nominal amount of generation outside the Southwest has dual-fuel capability and the dual-fueled plants are generally subject to severe air emission limitations that make alternate fuel use prohibitive for anything other than very short term emergency conditions.

Some of the WECC entities have taken steps to mitigate possible fuel supply vulnerabilities through obtaining long term, firm transport capacity on gas lines, having multiple pipeline services, natural gas storage, back-up oil supplies, maintaining adequate coal supplies, or acquiring purchase power agreements for periods of possible adverse hydro conditions.

Individual entities may have fuel supply interruption mitigation procedures in place, including on-site coal storage facilities. However, on-site natural gas storage is generally impractical so gas-fired plants rely on the general robustness of the supply chain and firm supply contracts. The diverse sources on gas line interconnections lessen concerns of wide-spread supply interruptions.

The 2008 to 2009 water year for WECC has been varied but overall WECC is below normal. California is in its third year of drought conditions, but the condition is being mitigated by lower demands due to the current recession. Although the water levels are low across WECC, resource adequacy takes into account drought conditions and it is anticipated that although energy output may be decreased, peaking capacity will remain available.

As of December 31, 2008, WECC's existing resource mix percentage of coal and gas/dual-fuel resources were 18.3 percent (36,389 MW) and 42.0 percent (83,700 MW), respectively. In 2018, the resource mix is projected to be 16.3 percent (39,867 MW) of coal and 42.3 percent (103,536 MW) of gas/dual-fuel resources.

Transmission

For the 2009 to 2018 period, 10,560 circuit miles of 100 and 500 kV transmission line additions have been reported to WECC. The results of the reported data are compiled in the tables below.

	AC Voltage (kV)				
Category	**100-161**	**200-299**	**300-399**	**400-599**	**Total AC**
*Existing as of 12/31/2008	49,245	42,764	10,694	16,642	**119,345**
Under Construction as of 1/1/2009	10	687	38	80	816
Planned - Completed within first five years	35	769	146	990	1,939
Conceptual - Completed within first five years	59	215	0	1,405	1,679
Planned - Completed within second five years	12	391	65	813	1,281
Conceptual - Completed within second five years	30	190	-84	4,709	4,845
Total Under Construction, Planned Line Additions	57	1,847	249	1,883	4,036
Total Conceptual	89	405	-84	6,114	6,524

Total Under Construction, Planned and Conceptual Line Additions	**147**	**2,252**	**165**	**7,997**	**10,560**
Total Line Additions	**49,392**	**45,016**	**10,859**	**24,639**	**129,905**

* The 100 kV class existing is made up of 115-161 kV lines, the 200 class was 230-240 kV, the 300 class was 287-340 and 345-450 kV classes and 400-599 was 500-525 kV classes

There are a large number of transmission projects that have been reported to WECC. Some of these projects are duplicative in nature and may have a proposed path similar to another project. A delay for most of these projects would not adversely impact the system, but there are some projects that could impact reliability listed in the subregional sections.

In addition to the currently planned transmission projects included in the preceding table, there are several large transmission project proposals that are not included. These projects range from 1,500 to 3,000 MW of transfer capability. These projects and others are in the early development stages and are not included in this assessment. They are only mentioned for informational purposes. Most of these projects would be associated with potential renewable energy projects and reinforcing the transmission system, but they could also help reduce future North-South transmission constraints such as the North-South split.

Examples include:

- Northern Lights–Celilo Project (Alberta to Oregon)
- Northern Lights–Inland Project (from Montana to Los Angeles and Phoenix)
- Frontier Line (from Montana and Wyoming to California)
- TransWest Express Project (from Wyoming to Arizona)
- Canada/Pacific Northwest to Northern California Study.

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in Section III of the WECC Planning Coordinating Committee's Handbook[137]. These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to enhance deliverability and to mitigate possible adverse power system conditions.

Operational Issues

Under WECC's current Regional reliability plan, two reliability centers have been established for the Region, one in Colorado and one in Washington. The reliability coordinators are charged with actively monitoring, on a real-time basis, the interconnected system conditions on a wide-area basis to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

[137] http://www.wecc.biz/committees/StandingCommittees/PCC/Shared%20Documents/PCC_Handbook_Complete.pdf

WECC operations personnel currently use the Westwide System Model (WSM), which is an energy management system (EMS) that allows monitoring of the electrical grid and provides contingency analysis, but does not allow any control.

Each of the balancing authorities and transmission providers has its own plans for complying with NERC EOP-002 standards pertaining to response to catastrophic events.

There are no problems anticipated with the scheduled maintenances during this study period.

Most of the BAs in WECC have Reserve Margins that account for temperature extremes. The target planning Reserve Margins developed for this *Long-Term Reliability Assessment* uses a 1-in-10 weather event as the proxy for extreme temperature conditions. However, if operating reserves decline below the required levels, operators could call on their various DSM programs, request public conservation, attempt to purchase power and as a last resort, initiate rolling firm load interruptions.

In addition, most of WECC's entities are members of various reserve sharing groups that may be called upon to provide additional energy under prescribed emergency conditions. Some of the reserve sharing groups have other conditions pertaining to the number of times it may be called upon and the length of time to cover (some are up to 168 hours).

The WECC Region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the Region is winter peaking while the southern portion of the Region is summer peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. However, transmission constraints between the subregions are a significant factor affecting economic use of this surplus energy. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

The integration of increasing levels of variable generation resources, specifically wind and solar, that may be required to meet state or local Renewable Portfolio Standards (RPS) raises operating issues. Integrating these resources reliably into the various areas may require BAs to change how they operate their system due to the intermittency of the generation from these resources. Variable resources place an increased demand on the traditional resources used to balance their systems. This may cause the BA to purchase better wind forecasting programs, require an increase in spinning reserves, or develop other methods to mitigate undesirable impacts on the system. As mentioned earlier, WECC has established the Variable Generation Subcommittee (VGS) to help examine issues related to planning for and operating with large amounts of variable generation.

The Los Angeles Department of Water and Power (LADWP) is considering the following methods to lessen the impact of variable resources in their BA:

- Refurbish additional existing pump-storage units and integrate their operation with wind energy output,

- Equip control systems on wind farms that are owned and operated by LADWP to allow LADWP operators to control power generation levels and ramp rates in order to maintain power system reliability.
- Retrofit hydro power plants along LADWP's aqueduct system to have the ability to follow load, if feasible.
- Repower existing old steam units with gas turbine units to provide quick start, low-minimum load, high-ramp rate operations, and frequent cycling ability.

The Bonneville Power Administration (BPA) BA has a current level of wind penetration of 20 percent, which is expected to grow to 60 percent around 2013. There is a question whether the Federal Columbia River Power system (FCRPS) will have sufficient flexibility to meet not only their current obligations but also support the increasing wind resources. The FCRPS currently is used to regulate generation, balance the system, and support wind-related operating requirements while also meeting its fish operations as required under the Endangered Species Act. BPA states the analysis also showed the federal dams do not have the flexibility to provide such high levels of reserves without violating stream-flow or fish protection requirements. Under the 2008 operating protocols, the hydro system alone cannot provide sufficient reserves to serve more than about 3,000 to 3,500 MW of wind power.

With planned additions (generation and transmission) , or future upgrades to existing facilities (new emission controls or other extended major maintenance items) over the next ten years, a different pattern of maintenance outages may be required on the existing system. Maintenance outages that affect the system will be timed and staged by the entities as much as possible to minimize any limitations on the system.

The Environmental Protection Agency is readdressing the Clean Water Act (CWA) Section 316(b) Phase II, which pertains of once-through-cooling (OTC) on existing power plants. The OTC process uses water from a river or ocean for condensing low-pressure steam to water as part of the thermal cycle of these units. In January 2007, the Second Circuit Court issued its decision (Decision) on the Phase II Rule litigation. The result of that Decision was to demand significant portions of the previous EPA 316 b rule back to the EPA. As a result, the EPA withdrew the Phase II Rule in its entirety and directed EPA Regions and states to implement §316 (b) on a Best Professional Judgment (BPJ) basis until the litigation issues are resolved. The issue of OTC will have the largest impact on the California-Mexico subregion, and is discussed further in that section.

In most cases, the projected retirement of existing generation has been associated with the construction of new resources and so there is not any adverse impact expected from retirements.

WECC does not foresee any operational problems or integration concerns with regard to renewable distributed generation systems, such as rooftop solar panels.

Reliability Assessment Analysis

WECC does not have an interconnection-wide formal planning Reserve Margin standard. As mentioned, part of the WECC annual Power Supply Assessment (PSA)[138] summer and winter reserve target margins are developed using a building block method. The building block method takes into account factors for weather, forced outages, operating reserves, and operating contingencies. These planning reserve target margins were held constant for the entire study period. One of the goals of the assessment is to identify subregions within the Western Interconnection that have the potential for electricity supply deficits below target margins based on reported total demand, resource, and transmission data.

WECC staff does not perform loss-of-load probability (LOLP) studies, but it does analyze the Reserve Margins for the various subregions described in the table below as part of the evaluation of resource adequacy. WECC only considers resources within the Western Interconnection when performing resource analysis. There are Reserve Sharing Groups (RSG) in each of the WECC subregions, and, in general, they only count on the resources within their subregion. In 2007, Sacramento Municipal Utility District (SMUD) BA and Turlock Irrigation District (TID) BA joined the Northwest Power Pool to share reserves across transmission interconnections within the NWPP. However, for purposes of the 2009 *Long-Term Reliability Assessment*, they are included in the California-Mexico subregion where they are geographically located. There are no entities within WECC that have reserve sharing agreements with entities external to WECC, unless the entity is a LSE or BA in another Region.

In the resource adequacy process, each BA is responsible for complying with the resource adequacy requirements of the state or provincial area(s) in which they operate. Some BAs perform resource adequacy studies as part of their IRPs, which usually look out 20 years. Other BAs perform resource adequacy studies that focus on the very short term (one to two years), but most projection extends into the future (10 to 20 years). In WECC's Power Supply Assessment (PSA), WECC uses a study period of 10 years, and uses the same zonal reserve requirements over the entire period.

There are several changes in the projections and components of the *2009 Long-Term Reliability Assessment* as compared to the *2008 Long-Term Reliability Assessment*. The effect of the recession has reduced the growth in the near term, resulting in higher Reserve Margins and a post recession growth rate that is higher than the near term. The overall growth rate for the 2009 to 2018 periods is approximately 0.5 percent less than in 2008. The new NERC future classifications—specifically the conceptual class—facilitate the inclusion of many types of future projects that would not have been included in the *2008 Long-Term Reliability Assessment*. In 2008, the Loads and Resources Subcommittee (LRS) assigned a confidence factor of zero to all conceptual resources, but in 2009 the LRS had the individual BAs assign FO and conceptual confidence factors to their resources for the *Long-Term Reliability Assessment* instead using a confidence factor of zero as is used for the WECC PSA.

Products that are energy-only, existing-uncertain wind (the portion of wind resources that is not expected to provide generation at the time of peak), and transmission-limited resources are not counted towards meeting resource adequacy in this *Long-Term Reliability Assessment*, nor WECC's PSA.

[138] http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/Forms/AllItems.aspx

Ten states with load internal to WECC have issued state-mandated Renewable Portfolio Standards (RPS).[139] These are discussed in the individual subregion sections. The RPS requirements have 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 available regulating reserves to accommodate the increased variability. If this trend continues, BAs with increasing levels of wind generation will likely 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 limitation procedures for use 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 on-peak capacity. 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.

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, which are responsible for performing and approving seasonal studies on significant paths, to determine the maximum SOL rating.

Planning authorities and the transmission planners are responsible for ensuring their areas are compliant with the TPL Standards 001 - 004. After these entities have created datasets and run simulations, they forward this data to WECC. The WECC System Review Work Group (SRWG) compiles and develops WECC-wide base cases under TPL-005-0, which is used for the WECC Annual Study Program.

The Annual Study Program[140] provides base cases for use by WECC members and staff to facilitate ongoing reliability and risk assessments of the Western Interconnection. The latest study program included the creation of 11 new power flow base cases and the simulation of 58 critical disturbance scenarios. Five of the power flow cases were prepared for conducting operating studies and the remaining six modeled various planning cases to year 2018. Disturbance simulations emphasize multiple contingency (N-2) outages (units and branches). Severe disturbances are simulated including loss of entire substations and entire generating plants to identify potential conditions leading to unacceptable system performance.

---

[139] http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm
[140] http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/TechStudies/Pages/default.aspx

The Annual Study Program rotates its focus on specific areas of subregions. For the 2008 Study Report, paths and RAS (remedial action scheme) or SPS (special protection system) in Colorado, Utah, and northern Nevada was the focus. Disturbances identified as critical outages within this area of study included transfer paths as well as initiating events for RAS (remedial action scheme) operation in the study focus area. The intent was to model system performance under stressed conditions with identified critical contingencies that might not normally be considered in operations, compare to long-term planning studies, and to identify potential concerns requiring further investigation.

In addition to providing WECC Members with an assessment of the WECC transmission system the Annual Study Program report helps support compliance with the following requirements in the NERC Reliability Standards relating to Reliability Assessment, Special Protection Schemes, and System Data.

- MOD 010,012—Steady State and Dynamics Data for Transmission System Modeling and Simulation
- FAC 005—Electrical Facility Ratings for System Modeling
- PRC 006—UFLS Dynamics Data Base
- PRC 014—Special Protection System Assessment
- PRC 020—UVLS Dynamics Data Base
- TPL 001-004—Transmission Planning (System Performance)

If the study results do not meet the expected performance levels established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: an islanding scheme for loss of the AC Pacific Intertie that separates the Western Interconnection into two islands and drops load in the generation-deficit southern island; a coordinated off-nominal frequency load shedding and restoration plan; measures to maintain voltage stability; a comprehensive generator testing program; enhancements to the processes for conducting system studies; and a reliability management system.

Operating studies and procedures are reviewed to ensure simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach for submission to WECC's Operating Transfer Capability Policy Committee.

On the basis of these ongoing activities, transmission system reliability within the Western Interconnection is expected to meet NERC and WECC standards throughout the ten-year period.

Transmission operators and planners perform reliability studies on their own system to ensure performance meets or exceeds NERC and WECC standards. As mentioned earlier in the transmission section, the WECC System 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.[141]

WECC has a Power System Stabilizer (PSS) standard that requires large generators with high initial response exciters to be equipped with a PSS and to have those PSS's properly tuned and in-service. The PSS acts to modulate the generator field voltage to dampen low frequency electrical power oscillations on the transmission system. Due to this standard and the studies required therein, WECC does not regularly perform interconnection-wide small signal stability studies.

The WECC TPL-(001-004)-WECC-1-CR-System Performance Criteria provides guidance on voltage support requirements, reactive power requirements, and disturbance performance criteria.[142] The WECC transient voltage dip criteria are contained within these criteria. Planning authorities and transmission planners are responsible for ensuring their respective areas are compliant with the WECC criteria and TPL Standards 001 - 004.

The Voltage Support and Reactive Power Standard sets the criteria for minimum dynamic reactive requirements. Dynamic reactive power support and voltage control are essential during system disturbances. Synchronous generators, synchronous condensers, and Static Var Compensators (SVC) provide this dynamic support.

Each year WECC sends out a data request letter to the Technical Studies Subcommittee (TSS) and the System Review Work Group (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 web site as the Voltage Stability Summary.[143] There are several BAs within WECC that participate in Under Voltage Load Shedding (UVLS) programs. Further details regarding these programs are presented in the subregional sections or are presented in the Voltage Stability Summary.

WECC does not have guidelines for on-site spare generator step-up transformers or spare auto-transformers. Some of the BAs within WECC participate in transformer-sharing programs such as the Edison Electric Institute (EEI) transformer program. BAs generally maintain an inventory of transformers for their area or system. If an entity is in need of substation hardware (transformer, PCB, etc), especially on an emergency basis, they can contact the Substation Work Group (SWG) Chair and he will send a blanket email to the members of the SWG and request direct communication back to the requester if the equipment is available, either on loan or for purchase.

---

[141] http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/TechStudies/Pages/default.aspx

[142] http://www.wecc.biz/Standards/WECC%20Criteria/TPL%20–%20(001%20thru%20004)%20–%20WECC%20–%201%20–%20CR%20-%20System%20Performance%20Criteria.pdf

[143] http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2fcommittees%2fStandingCommittees%2fPCC%2fTSS%2fShared%20Documents%2fVoltage%20Stability%20Summaries&FolderCTID=&View=%7bC302382F%2d5B3A%2d4BA1%2dAB26%2dEC74407432E8%7d

Regional Description

WECC's 262 members, including 37 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.

Subregions

Northwest Power Pool (NWPP) Area

Peak Demand and Energy

The Northwest Power Pool (NWPP) area is a winter-peaking subregion and is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of northern California; and the Canadian provinces of British Columbia and Alberta. For the period from 2009 to 2018, winter total internal demands are projected to grow at annual compound rates of 1.50 percent and 1.90 percent in the United States and Canadian areas, respectively. The annual energy requirements are also projected to grow at the highest annual compound rates of 1.54 percent and 2.50 percent.

	Winter (MW)	Peak	Demands	Annual Energy Use (GWh)		
	NWPP	NWPP US	NWPP CN	NWPP	NWPP US	NWPP CN
2008 Actual	64,786	44,045	20,769	383,100	250,441	132,659
2009 Projected	62,952	41,681	21,548	370,489	234,132	136,357
Growth %	-2.83	-5.37	3.75	-3.29	-6.51	2.79
2018 Projected	72,955	47,639	25,514	438,990	268,651	170,339
2009 – 2018 Growth %	1.65	1.50	1.90	1.90	1.54	2.50

The annual energy use for NWPP increased by 1.27 percent, from 378,304 GWh in 2007 to 383,100 GWh in 2008. The 2008 energy use was 0.1 percent less than the forecast in last year's assessment (1.64 percent greater for the U.S. and 3.18 percent less for the Canada areas). Annual energy use for the ten-year period from 2008 to 2018 is forecast to increase at a rate of 1.37 percent. This is larger than the historic annual energy use increase of 1.1 percent from 1998 to 2008. For the period from 2008 to 2018, the annual energy requirements are projected to grow at annual compound rates of 0.70 percent and 2.53 percent in the U.S. and Canada areas, respectively.

One of the contributors to Canada's growth is the development and production of oil from oilsands. Currently, the industrial sector of AESO consumes 49 percent of the energy in the province of Alberta. Oilsands producers currently consume 11 percent of the energy in the province and are expected to consume 23 percent by 2018.

Operational Issues

Under normal weather conditions, NWPP does not anticipate dependence on imports from external areas during winter peak demand periods, In the event of either extreme weather or much lower than normal precipitation, the NWPP could increase diversity exchange imports which would reduce reservoir drafts and aid reservoir filling.

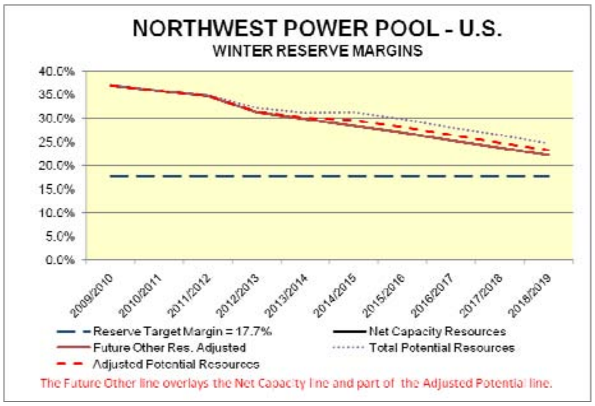
In an effort to accommodate new wind resources and maintain system reliability, BPA and other BAs have had to increase their regulating Reserve Margins to compensate for the variability of these resources. As mentioned earlier, BPA states the analysis also showed the federal dams do not have the flexibility to provide such high levels of reserves without violating stream flow or fish protection requirements. Under the 2008 operating protocols, the hydro system alone cannot provide sufficient reserves to serve more than about 3,000 to 3,500 MW of wind power. Currently the NWPP is projecting more than 5,000 MW of planned wind generation by 2018. If this comes to fruition, regulating reserves from other resources may be needed. Since 2008, the wind developers in the BPA BA have improved their short-term wind generation forecasting ability resulting in less need for regulating reserves. BPA currently believes that Federal hydro resources can integrate on the order of 6,000 MW. However, interest in developing wind projects has also increased. By 2019, it is now considered plausible that the wind fleet in BPA's BA will grow to 11,000 MW.

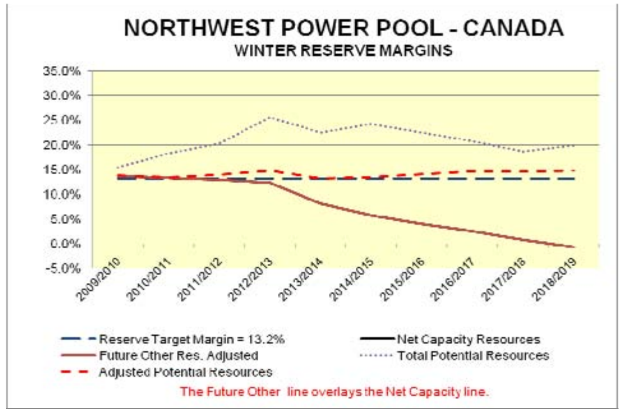
Resource Adequacy Assessment

For the entire NWPP subregion, the target winter Reserve Margin is 16.6 percent. Projected winter Reserve Margins exceed the target margin until winter 2017 to 2018 when the projected margin is 15.6 percent. By winter 2018/2019, the projected margin declines to 14.0 percent.

The target winter Reserve Margin for the United States portion of the NWPP is 18.4 percent. The data indicate a winter 2009/2010 Reserve Margin of 37.0 percent with net capacity resources. By winter 2013/2014, the margin declines to 29.9 percent and by the winter of 2018/2019, the margin declines 22.0 percent. WECC’s forecast surplus Reserve Margin exists due to the Columbia River Basin hydroelectric dams located in the NWPP-US, but deliverability of that capability to other areas is problematic due to both the possibility of a constrained North-to-South transfer capability and the limited energy storage capability associated with the hydro system.

For the Canadian area, the target winter Reserve Margin is 13.2 percent. As indicated in the chart below, the Canada subregion margin drops below the target margin starting with winter 2011/2012. When including the adjusted potential resources, the Canadian portion of NWPP does not go negative during the study period. The Canadian entities are aware of the need for resource adequacy and transmission reinforcement and believe that through the open market and proper planning adequate resources will be available throughout the ten-year assessment period.





Note – Due to energy constraints on the operation of the hydro system in the Northwest, much of this surplus may be unavailable to meet multi-hour load requirements, including transfers to other subregions of WECC

Generation in the province of Alberta operates in a fully deregulated market and resource additions are market driven. The deregulated market is operated by the Alberta Energy System Operator (AESO). Generation additions and load growth are expected to result in some transmission constraints in a number of areas over the course of the review period if identified system reinforcements are not completed on time. The impact of most of these constraints is anticipated to be local in nature and will not impact transmission systems outside of Alberta.

The AESO has instituted "The Two Year Probability of Supply Adequacy Shortfall Metric"[144] which is a probabilistic assessment of encountering a supply shortfall over the next two years. The calculation estimates on a probabilistic basis how much load may go without supply over the next two-year period. Based on extensive consultation with their stakeholders, when this unserved energy exceeds 1,600 MWh in any two year period (equivalent to a one-hour 800 MW shortfall in each of the two years), the party may take certain actions to bridge the temporary supply adequacy gap without impacting investor confidence in the market. The method of bridging the gap may be in the form of 1) Load Shed Service (LSS), 2) self supply and back-up generation support from existing backup generation owned by commercial businesses etc., and 3) emergency portable generation.

NWPP planning is conducted by sub-area. Idaho, northern Nevada, Wyoming, Utah, British Columbia, and Alberta individually optimize their resources to their demand. The coordinated system (Oregon, Washington, and western Montana) coordinate the operation of its hydro resources to serve its demand. In 2001, the northwest experienced its second lowest coordinated Columbia River System volume runoff since record keeping began, with reservoirs refilling to just 71 percent of capacity, the lowest levels in almost a decade. Since 2001, the reservoir refill has ranged between 87 percent and 94 percent of capacity.

The reservoirs are managed to address all of the competing requirements including, but not limited to: current electric power generation, future (winter) electric power generation; flood control; fish and wildlife requirements; special river operations for recreation; irrigation;

[144] http://www.aeso.ca/market/17855.html

navigation; and refilling of the reservoirs. In addition to managing the competing requirements, other available generating resources, market conditions, and load requirements are considered and incorporated into the decision for refilling the reservoirs. Any time precipitation levels are below normal, balancing these interests becomes even more difficult. A ten-year agreement was reached in 2000 among parties involved in operation of the Columbia River Basin concerning river operations. The net impact of the agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor fish migration. The capability reduction, which varies depending on water flows and other factors, is reflected in the margin calculations presented in this report. The agreement includes a provision for negotiating changes in the plan under emergency conditions as occurred in 2001.

The Northwest Power and Conservation Council has adopted resource adequacy assessment standards for the Pacific Northwest (PNW) portion of the subregion (representing approximately 25 percent of the load), which consists of the states of Oregon, Washington, Idaho, and a portion of Montana. The adopted energy and capacity-adequacy standards are both tied to probabilistic analyses targeting a loss of load probability of 5 percent or less. The remaining portions of the subregion have not established a formal process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel Supply and Delivery

A significant portion of the electric power generated in the Pacific Northwest is derived from hydroelectric generation. Hence, wide variations in annual precipitation, water storage and flow limitations, and other factors significantly affect energy generation from other resources and complicate the fuel-planning processes. Coal-fired generation in the area is also prevalent. Much of the coal-fired generation is near the fuel sources and is generally operated in a base-load mode. Consequently, the area is not highly reliant on gas-fired plants relative to annual energy generation and many of those plants are operated as seasonal peaking units.

Wind generation is increasing rapidly in the area. As of December 31, 2008, the NWPP has 50.6 percent of WECC’s nameplate wind resources (4,434 MW), and 47.4 percent of the expected summer on-peak wind capacity (751 MW). The expected summer on-peak generation is 381 MW for the future planned resources and 5 MW for the adjusted resources. Of the future new wind resources in WECC, NWPP accounts for 6,973 MW (31 percent) of the non-derated resources and 386 MW (19 percent) of the summer on-peak resources. Since the wind resources exhibit fluctuations in output, BAs with relatively large amounts of wind generation are investigating the costs and options for integrating wind. Careful and site-specific assessments are needed to minimize adverse consequences that may occur.

Existing and Potential Resources (NWPP through July 31, 2018)						
	*Existing (MW)	*Existing Other (MW)	Future Planned (MW)	Potential Future Other (MW)	Potential Conceptual (MW)	Total New Resources 2018
Total Installed	**90,626**		**8,410**	**0**	**8,948**	**17,358**
Conventional	36,802		1,352	0	5,438	6,790
Hydro	48,913		1,571	0	1,575	3,146
Wind	4,085		5,266	0	1,707	6,973
Biomass	826		221	0	228	449
Solar	0		0	0	0	0
	*Existing Certain (MW)	*Existing Other (MW)	Future Planned (MW)	**Adjusted Future Other (MW)	**Adjusted Conceptual (MW)	Total New Resources 2018
Total Expected Resources	**83,503**		**3,404**	**0**	**4,432**	**7,836**
Conventional Expected	36,802		1,252	0	3,709	4,961
Hydro Expected	45,149		1,521	0	563	2,084
Wind Expected	726		381	0	5	386
Biomass Expected	826		250	0	155	405
Solar Expected	0		0	0	0	0
Derates or Maintenance		**7,123**	**4,720**	**0**	**2,449**	**7,169**
Hydro Derate		3,764	0	0	0	0
Wind Derate		3,359	4,935	0	1,159	6,094
Biomass Derate		0	21	0	0	21
Solar Derate		0	0	0	0	0
Scheduled Outages		3,146				0
Confidence Factor				**0%**	**68%**	

Transmission Assessment

Because of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of accommodating anticipated transfers among NWPP systems, addressing several areas of constraint within Washington, Oregon, Montana, and other areas within the Region, and integrating new generation. Projects at various stages of planning and implementation include approximately 2,972 miles of 500 kV transmission lines.

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission planning and operations. In order to support maximum import transfer capabilities under double-circuit simultaneous outage conditions, the northwest depends on an automatic under-frequency load-shedding scheme.

Northwest Power Pool – Transmission Line Circuit Miles	AC Voltage (kV)				
Category	100-120	200-299	300-399	400-599	Total AC
*Existing as of 12/31/2008	28,292	21,109	4,896	9,790	64,807
Under Construction as of 1/1/2009	10	88	38	79	215
Planned - Completed within first five years	0	37	146	494	677
Conceptual - Completed within first five years	15	67	0	760	842
Planned - Completed within second five years	12	0	65	153	230
Conceptual - Completed within second five years	0	28	-84	1,486	1,430
Total Under Construction, Planned Line Additions	22	125	249	726	1,122
Total Line Additions	15	95	-84	2,246	2,272

* The 100 kV class existing is made up of 115 – 161 kV lines, the 200 class was 230-240 kV, the 300 class was 287 - 340 and 345-450 kV classes and 400 - 599 was 500-525 kV classes

Power flow studies have been conducted by the transmission planning authorities and in some cases where there have been N-1 and N-2 critical contingencies identified, mitigation measures (e.g., adding reactive sources) or new facilities (e.g., adding a new transformer) have been proposed. Because some of these improvements are driven by future load growth requests not yet firmed up by the customers, some of these measures have not yet escalated to the project level and no specific date for their completion has been assigned.

Some balancing authorities are taking steps to help make the transmission queue and transmission queue assessment processes more efficient. BPA has instituted a process called the Network Open Season[145] (NOS) for allowing resources placement in its transmission queue. Under the NOS, those seeking transmission capacity are asked to sign Precedent Transmission Service Agreements (PTSA), which commit them to take service at a specified time and under specified terms. At one time, BPA's transmission queue was over 18,000 MW. After the first phase of the 2008 NOS there were 6,410 MW worth of transmission requests made and PTSAs signed by customers. The PSTA contract is still contingent on BPA's ability to offer new service at its embedded cost rate and is subject to BPA's completion of the required environmental work prior to construction of new facilities.

Preliminary analysis for WECC's 2009 Supply Adequacy Model (SAM) results indicates that transmission constraints occur between the United States and Canadian portions of the NWPP due to economic diversity exchanges.

Approvals of need for a number of system reinforcements have been received from the Alberta provincial regulator. One of these is for the development of approximately 105 kilometers (65 miles) of 240 kV transmission line to accommodate several new wind generation developments in southwest Alberta. This development has a projected in-service date of June 2010. Other projects include the installation of two 600 MVA 240 kV phase shifting transformers (the first in

145 http://www.bpa.gov/corporate/pubs/fact_sheets/08fs/fs_Network_Open_Season.pdf

Alberta) to be used to balance the flows between the northwest and the northeast Regions of the province. AESO's transmission plan can be found at http://www.aeso.ca.

In Alberta, a project to reinforce the downtown area of Edmonton with the addition of 6 miles of underground 240 kV cable was completed and put in-service in November 2008.

Planning efforts continue on a number of other major system reinforcements including supply into the Fort Saskatchewan and Fort McMurray areas of Northeast Alberta. This reinforcement will likely be a combination of 500 kV and 240 kV developments. Planning efforts are also continuing on reinforcing the main north–south transmission grid in Alberta. For various reasons the need approval for this project was rescinded by the regulator. It is anticipated this project will be in-service in the 2012 time frame.

AESO has an Under Voltage Load-Shedding (UVLS) scheme. There are approximately 300 MW currently connected to the UVLS. This does not influence AESO's reliability assessment.

A Calgary-area transmission must run (TMR) procedure addresses 240 kV transmission grid-loading issues and ensures voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta, near Calgary, and assist in maintaining overall system security.

British Columbia relies on hydroelectric generation for 90 percent of its energy production. British Columbia Transmission Corporation (BCTC) is responsible for the planning, operation, and maintenance of British Columbia's publicly owned transmission system. BCTC is addressing constraints between remote hydro plants, Lower Mainland (LM) and Vancouver Island (VI) load centers. The Vancouver Island Transmission Reinforcement[146] project was completed in December 2008 and involved the removal of two 138 kV lines (one submarine) and replacing them with a 230 kV double circuit infrastructure including a 230 kV underwater cable between Arnott substation and Vancouver Island terminal. A key transmission shortage that faces BCTC currently is the Interior to LM path. The Interior to Lower Mainland[147] (ILM) transmission project is BCTC's largest expansion project in 30 years for the province. In August of 2008, the BC Utility Commission approved the ILM project, which is a new 500 kV line between the Nicola and Meridian substations, with a projected in-service date in 2014. BCTC is planning to rely upon the existing 905 MW conventional steam plant located in the major load center and the 1250 MW Canadian entitlement from the NWPP U.S. to meet the LM/VI resource requirements in the interim period. The ILM reinforcement project will increase the total transfer capability of the interior to lower mainland area grid and the new 230 kV cable increased the transfer capability from the lower mainland area to Vancouver Island.

BCTC has Under Voltage Load-Shedding (UVLS) schemes installed for LM and VI systems to prevent voltage collapse. These schemes monitor the voltage at the key substations in VI and LM, and the var reserves at VI transmission synchronous condensers and Burrand generation station. If the voltages and the var reserves are lower than the settings, the selected loads in VI

[146] http://www.bctc.com/projects/vitr/
[147] http://www.bctc.com/projects/ilm/

and LM will be shed. The maximum load-shedding amount is about 1,690 MW. BCTC is not expecting to install any more new UVLS.

Rocky Mountain Power Area

Peak Demand and Energy

The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season. For the period from 2009 to 2018, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 1.58 percent and 1.61 percent, respectively. The difference in 2018 between the net capacity resources (15,102 MW) and the total internal demand plus target margin (14,831 MW) is 271 MW (this includes serving 378 MW of interruptible load).

Rocky Mountain Power Area	Summer Peak Demands (MW)	Annual Energy Use (GWh)
2008 Actual	11,579	65,103
2009 Projected	11,224	67,662
Growth %	-3.1%	3.9%
2018 Projected	13,252	78,096
2009 – 2018 Growth %	1.9%	1.6%

Annual energy use increased by 3.26 percent from 63,050 GWh in 2007 to 65,103 GWh in 2008. The 2008 energy use was 1.3 percent greater than the forecast in last year's assessment. The annual energy use for the ten-year period from 2008 to 2018 (78,096 GWh) is forecast to increase by 1.84 percent annually. This compares to the historic annual energy use growth of 3.08 percent from 1998 to 2008. Annual energy use for the nine-year period from 2009 to 2018 is forecast to increase by 1.61 percent.

Resource Adequacy Assessment

The RMPA target Reserve Margin is 17.1 percent for the summer and 15.4 percent for the winter. The RMPA expects a summer 2009 Reserve Margin of 12.4 percent without any new generation or expected purchases and 17.1 percent with net capacity resources (including serving interruptible load). The Reserve Margin does not go below the target margin with the net capacity resources during the entire study period.

As of December 31, 2008, the RMPA has 12.7 percent of the WECC wind capacity (nameplate). This is derated to 134 MW during the summer peak period (9.0 percent of the WECC on-peak wind capacity). The table below provides a more detailed breakdown of the RMPA resources.

Existing and Potential Resources (RMPA through July 31, 2018)						
	***Existing (MW)**	***Existing Other (MW)**	**Future Planned (MW)**	**Potential Future Other (MW)**	**Potential Conceptual (MW)**	**Total New Resources 2018**
Total Installed	**14,363**		**1,379**	**0**	**1,864**	**3,243**
Conventional	11,830		1,221	0	1,743	2,964
Hydro	1,417		0	0	0	0
Wind	1,109		150	0	120	270
Biomass	3		0	0	0	0
Solar	4		8	0	1	9
	***Existing Certain (MW)**	***Existing Other (MW)**	**Future Planned (MW)**	****Adjusted Future Other (MW)**	****Adjusted Conceptual (MW)**	**Total New Resources 2018**
Total Expected Resources	**13,268**		**1,240**	**0**	**1,044**	**2,284**
Conventional Expected	11,826		1,213	0	1,020	2,233
Hydro Expected	1,301		0	0	0	0
Wind Expected	134		19	0	23	42
Biomass Expected	3		0	0	0	0
Solar Expected	4		8	0	1	9
Derates or Maintenance		**1,095**	**139**	**0**	**83**	**222**
Hydro Derate		116	0	0	0	0
Wind Derate		975	131	0	47	178
Biomass Derate		0	0	0	0	0
Solar Derate		4	8	0	2	10
Scheduled Outages		0				0
Confidence Factor				**0%**	**59%**	

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel Supply and Delivery

Coal, hydro, and gas-fired plants are the dominant electricity sources in the area. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants, however, may experience operational limitations due to variations in precipitation. As in the northwest, gas-fired plants are most often operated in a peaking mode. Abundant natural gas supplies exist within the area but delivery constraints may occur at some plants during unexpected severe cold weather conditions.

Transmission Assessment

Tri-State Generation and Transmission is proposing a project in southern Colorado called the San Luis Valley Electric System Improvement project. The project would involve the construction of an 80 mile 230 kV transmission line between the Walsenburg Substation and the

San Luis Valley Substation. The San Luis Valley's existing electrical system has reached its limit due to continued residential and irrigation growth. One major concern is the radial nature of the existing 230 kV transmission system does not provide the reliability benefits of redundant service. The other major problem currently experienced on the transmission system is a drop in voltage that occurs when the load on the electric system in the valley is above 65 MW. This line will provide the power delivery infrastructure to increase the reliability and capacity of the existing transmission system and support proposed renewable energy development in the area.

The Western Area Power Administration (WAPA) plans to upgrade several 115 kV transmission lines to 230 kV over the next ten years to increase transfer capabilities and help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado. In addition to those conversions, the table at the end of WECC's self-assessment describes additional transmission projects.

Rocky Mountain Power Area – Transmission Line Circuit Miles	**AC Voltage (kV)**				
Category	**100-120**	**200-299**	**300-399**	**400-599**	**Total AC**
*Existing as of 12/31/2008	6,081	5,146	982		12,209
Under Construction as of 1/1/2009	0	327	0	0	327
Planned - Completed within first five years	0	97	0	0	97
Conceptual - Completed within first five years	0	0	0	0	0
Planned - Completed within second five years	0	137	0	0	137
Conceptual - Completed within second five years	0	0	0	0	0
Total Existing, Under Construction, Planned Line Additions	6,081	5,707	982	0	12,770
Total Line Additions	**6,081**	**5,707**	**982**	**0**	**12,770**

* The 100 kV class existing is made up of 115 – 161 kV lines, the 200 class was 230-240 kV, the 300 class was 287 - 340 and 345-450 kV classes and 400 - 599 was 500-525 kV classes

There are currently over 325 miles of 230 kV transmission lines that are under construction and over 425 miles of 345 kV transmissions planned for construction within the next five years in the RMPA subregion.

Operational Issues

Transmission upgrades in the area have alleviated some transfer capability limitations, but some system constraints remain. Operator flexibility will be limited by the transmission constraints and operating conditions must be closely monitored, especially during periods of high demand. In some cases, special protection schemes are used to preserve system adequacy should multiple outage contingencies occur.

The Colorado RPS for municipal utilities is an annual energy mandate of: one percent of retail sales by 2008; three percent by 2011; six percent by 2015 and 10 percent by 2020. Public Service Company of Colorado (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 and 80 percent depending on the location and type of solar resource. PSCo uses a 70 percent capacity value for their solar resources.

Arizona-New Mexico-Southern Nevada Power Area

Peak Demand and Energy

The Arizona-New Mexico-Southern Nevada (AZ-NM-SNV) power area consists of Arizona, most of New Mexico, southern Nevada, the westernmost part of Texas, and a portion of southeastern California. For the period 2009 to 2018, summer total internal demands and annual energy requirements are projected to grow at annual rates of 2.28 percent and 2.43 percent, respectively.

AZ-NM-SNV	Summer Peak Demands (MW)	Annual Energy Use (GWh)
2008 Actual	28,865	137,242
2009 Projected	30,452	140,254
Growth %	5.5	2.2
2018 Projected	37,300	174,142
2009 – 2018 Growth %	2.3	2.4

The annual energy use decreased by 1.92 percent from 139,932 GWh in 2007 to 137,242 GWh in 2008. The 2008 energy use was 4.01 percent less than the forecast in last year's assessment. For the ten-year period from 2008 to 2018, the energy use is forecasted to increase by 2.40 percent compared to the historic annual energy use increase of 3.49 percent from 1998 to 2008. The annual energy use from 2009 to 2018 is forecast to increase by 2.43 percent.

Resource Adequacy Assessment

The AZ-NM-SNV planning Reserve Margin target is 17.8 percent for the summer and 15.5 percent for the winter. The 2018 total internal demand includes serving 493 MW of interruptible load and 425 MW of direct-control load management. If the net internal demand was only to be met, it would result in a 19.2 percent Reserve Margin. If the adjusted potential resources are included, the Reserve Margin would be 23.2 percent. Two of the major differences between last year's forecasted Reserve Margins and the current projections for the AZ-NM-SNV subregion are: 1) lower loads and more existing and projected resources within the subregion; and 2) more resources and lower loads in California, allowing the purchase of more economic energy.

Existing wind resources within the AZ-NM-SNV subregion total 306 MW, which is derated to 33 MW during the summer peak period. The future planned and adjusted conceptual wind resource additions are projected to be 100 MW and 622 MW respectively, derated to 14 MW and 20 MW on-peak, respectively.

In Arizona, the renewable portfolio is a set of financial incentives from a large number of programs.[148] The RPS 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 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 that was established by the Public Utilities Commission of Nevada (PUCN) that requires 20 percent energy 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.

Existing and Potential Resources (AZ-NM-SNV through July 31, 2018)						
	*Existing (MW)	*Existing Other (MW)	Future Planned (MW)	Potential Future Other (MW)	Potential Conceptual (MW)	Total New Resources 2018
Total Installed	**41,950**		**2,137**	**160**	**5,301**	**7,598**
Conventional	36,854		1,754	5	3,037	4,796
Hydro	4,659		3	0	0	3
Wind	306		100	100	1,524	1,724
Biomass	81		0	50	0	50
Solar	50		280	5	740	1,025
	*Existing Certain (MW)	*Existing Other (MW)	Future Planned (MW)	**Adjusted Future Other (MW)	**Adjusted Conceptual (MW)	Total New Resources 2018
Total Expected Resources	**41,045**		**1,999**	**0**	**1,438**	**3,437**
Conventional Expected	36,850		1,687	0	1,123	2,810
Hydro Expected	4,031		3	0	0	3
Wind Expected	33		14	0	20	34
Biomass Expected	81		0	0	0	0
Solar Expected	50		295	0	295	590
Derates or Maintenance		**901**	**56**	**107**	**1,649**	**1,812**
Hydro Derate		628	0	0	0	0
Wind Derate		273	93	0	589	682
Biomass Derate		0	0	0	0	0
Solar Derate		0	45	0	73	118
Scheduled Outages		0				0
Confidence Factor				**0%**	**40%**	

148 http:/www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&state=AZ

The New Mexico Public Regulation Commission (PRC) established an RPS of 20 percent by 2020. In August 2007, the PRC issued an order[149] 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.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in this area will depend on how much new capacity is actually constructed. Frequently, resource acquisitions, including load reduction options, are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc. These factors combine to make resource adequacy forecasting problematic over an extended period of time.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource planning process or other similar process.

Fuel Supply and Delivery

Coal, hydro, and nuclear plants are the dominant electricity sources in the area. Gas-fired plants are most often operated in a peaking mode. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Major hydroelectric plants are located at dams with significant storage capability, so short-term variations in precipitation are not a significant factor in fuel planning.

Transmission Assessment

Transmission providers from AZ-NM-SNV, along with other stakeholders from southern California, are actively engaged in the Southwest Transmission Expansion Planning (STEP) group. The goal of this group is to collaborate in the planning, coordination, and implementation of a robust transmission system between Arizona, southern Nevada, Mexico, and southern California that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The STEP group has developed three projects resulting from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades was completed in 2006 and increased the transfer capacity by 505 MW. The second set of upgrades was to increase the transfer capacity by 1,245 MW and many have been completed. The third and last set of upgrades is the Palo Verde to Devers #2 500 kV transmission line (PVD2). This third set of upgrades as proposed by the STEP group developed complications in 2007 with the Arizona Corporation Commission's refusal to grant a permit for the construction of the PVD2 line, which may cancel or delay the construction of the line. In May 2009, Southern California Edison (SCE) dropped the Arizona portion of the proposed line and announced that it would proceed to construct the California portion in 2010. During the years that the line has been proposed the resource situation changed drastically, and SCE now believes that the California portion of the line is useful for central station solar projects being planned for the eastern portion of the state. This line was not included in this year's *Long-Term Reliability Assessment* or PSA analysis

[149] http://www.nmprc.state.nm.us/renewable.htm

since, in last year's SAM analysis; the line did not have an impact on transfers due to the AZ-NM-SNV being short on resources.

EXISTING AND FUTURE TRANSMISSION
(CIRCUIT MILES)

-AZ-NM-SNV – Transmission Line Circuit Miles Category	AC Voltage (kV) 100-120	200-299	300-399	400-599	Total AC
*Existing as of 12/31/2008	5,127	3,688	4,465	2,282	15,562
Under Construction as of 1/1/2009	0	0	0	1	1
Planned - Completed within first five years	35	279	0	143	457
Conceptual - Completed within first five years	44	0	0	28	72
Planned - Completed within second five years	0	94	0	660	754
Conceptual - Completed within second five years	30	162	0	715	907
Total Existing, Under Construction, Planned Line Additions	5,162	4,061	4,465	3,086	16,774
Total Line Additions	**5,236**	**4,223**	**4,465**	**3,829**	**17,753**

* The 100 kV class existing is made up of 115-161 kV lines, the 200 class was 230-240 kV, the 300 class was 287–340, and 345-450 kV classes, and the 400-599 class was 500-525 kV.

As mentioned earlier, the Department of Energy (DOE) has also studied various areas of congestion and identified the desert southwest as an area of concern, proposing the Southwest Area National Corridor, which includes counties in California and Arizona.

Operational Issues

Special protection schemes play an important role in maintaining system adequacy should multiple system outages occur. These schemes include generator tripping in response to specific transmission line outages. In addition, operators rely on procedures such as operating nomograms so the system can respond adequately to planned and unplanned transmission or generation outages.

California-Mexico Power Area

Peak Demand and Energy

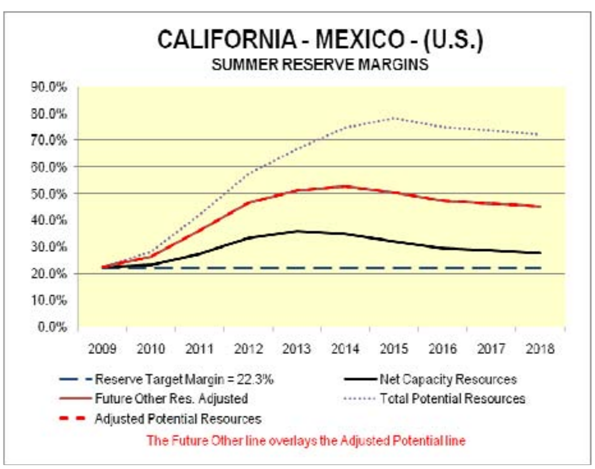
The California-Mexico power area encompasses most of California and the northern portion of Baja California, Mexico. Summer total internal demands are currently projected to grow at annual compound rates of 0.87 percent and 2.37 percent in the United States and Mexico areas, respectively, from 2009 to 2018. Annual energy use is projected to grow at annual compound rates of 1.23 percent and 2.00 percent in the U.S. and Mexican areas, respectively. The difference in 2018 between the net capacity resources and the total internal demand plus target margin (84,992 MW – (71,333 MW + 10,333 MW)) is 3,326 MW. This Reserve Margin while serving the total load is 19.1 percent (This includes serving 1,317 MW of interruptible load, 1,100 MW of direct control load management, 2,302 MW of load as a capacity resource and 48 MW of critical peak-pricing). If the net internal demand were only to be met, it would result in a 27.7 percent Reserve Margin. Of the 26,378 MW of total future planned resources (summer peak rating) throughout WECC, about 19,633 MW are projected for the California-Mexico Area. California, which generally peaks in August, stays above its target margin during the assessment period. California accounts for 2,816 MW or 65.6 percent of the 4,290 MW of available Direct Control Load Management (DCLM) reported for the 2009 summer period.

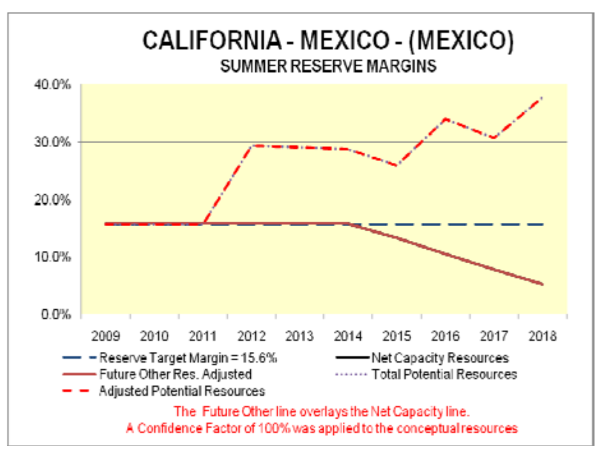
	Summer Peak Demand (MW)			Annual Energy Use (GWh)		
	CAMX	CMUS	CMMX	CAMX	CMUS	CMMX
2008 Actual	57,725	55,688	2,037	304,225	292,905	11,320
2009 Projected	63,352	61,237	2,115	307,055	296,368	10,687
Growth %	9.8%	10.0%	3.8%	0.9%	1.2%	-5.6%
2018 Projected	68,839	66,227	2,612	343,692	330,919	12,773
2009 – 2018 Growth %	0.9%	0.9%	2.4%	1.3%	1.2%	2.0%

The load forecasts submitted by some of the California balancing authorities in February 2009 reflected the California Energy Commission's 2008 load forecast and may no longer reflect their views of future loads as a result of the deepening recession. Newer studies of 2009 and 2010 show steep drops in load forecasts compared to recorded experience. The extent to which California-Mexico economies will recover to the levels implied by the official load forecasts for years 2011 to 2018 submitted to WECC as part of the *2009 Long-Term Reliability Assessment* cycle is now an open question.

Resource Adequacy Assessment

The California-Mexico total area (CA-MX) planning Reserve Margin is 22.1 percent for the summer and 15.7 percent for the winter. The planning Reserve Margins for California U.S. are 22.3 percent and 15.9 percent for the summer and winter, respectively. The planning Reserve Margins for Baja Mexico are 15.6 percent and 10.1 percent for the summer and winter, respectively. For the U.S. portion of the subregion, the Reserve Margin does not fall below the target Reserve Margin during the assessment period. For the Baja Mexico portion of the subregion, net capacity resources, including SAM-modeled imports from the United States, are sufficient for the area to meet target margins only through 2014. Hence, it is important that a significant portion of the area's conceptual resources enter service in a timely manner.





This picture of projected margins is entirely different from that presented in the *2008 Long-Term Reliability Assessment*. Numerous resource additions with low individual probability of being constructed collectively comprise substantial aggregate additions. Of course, this simple picture cannot portray the dilemma of knowing whether or not all of the proposed resources are deliverable to load in the timeframes proposed by the project proponents. In-depth transmission interconnection assessments and more aggregate planning studies are underway to discern the transmission requirements associated with this vast expansion of proposed projects. The results of these studies may affect the confidence factors associated with specific projects in future *Long-Term Reliability Assessment* cycles.

Of the existing wind resources within WECC, (8,476 MW of nameplate and derated to 1,753 MW on-peak) the CMUS has 2,972 MW which is derated to 726 MW during the summer peak period. Of the future WECC planned and adjusted future other wind resources, the CMUS accounts for 9,340 MW. The expected derated summer on-peak value is 2,124 MW. The CAUS has 351 MW of existing solar capacity. Of the future planned and adjusted future other solar resources, the CMUS accounts for 14,725 MW (expected/derated summer on-peak capacity).

Existing and Potential Resources (CAMX through August 31, 2018)						
	*Existing (MW)	*Existing Other (MW)	Future Planned (MW)	Potential Future Other (MW)	Potential Conceptual (MW)	Total New Resources 2018
Total Installed	**70,010**		**41,927**	**0**	**1,358**	**43,285**
Conventional	52,289		17,473	0	863	18,336
Hydro	13,662		65	0	390	455
Wind	2,972		9,340	0	105	9,445
Biomass	736		324	0	0	324
Solar	351		14,725	0	0	14,725
	***Existing Certain (MW)**	***Existing Other (MW)**	**Future Planned (MW)**	****Adjusted Future Other (MW)**	****Adjusted Conceptual (MW)**	**Total New Resources 2018**
Total Expected Resources	**63,043**		**30,749**	**0**	**864**	**31,613**
Conventional Expected	48,778		13,513	0	567	14,080
Hydro Expected	12,452		63	0	256	319
Wind Expected	726		2,124	0	41	2,165
Biomass Expected	736		324	0	0	324
Solar Expected	351		14,725	0	0	14,725
Derates or Maintenance		**3,866**	**33,549**	**0**	**43**	**33,592**
Hydro Derate		1,210	0	0	0	0
Wind Derate		2,246	7,216	0	28	7,244
Biomass Derate		292	19	0	0	19
Solar Derate		118	2,930	0	0	2,930
Scheduled Outages		117				0
Confidence Factor				**0%**	**66%**	

In June of 2006 California passed Assembly Bill 32, *the California Global Warming Solutions Act of 2006*, which had a significant influence on how California plans to meet its future needs and cap California's greenhouse gas emissions at the 1990 level by 2020. On December 5, 2007

California adopted *the 2007 Integrated Energy Policy Report (IEPR)*[150] which states that "Scenario analysis indicates that these aggressive cost-effective efficiency programs, when coupled with renewables development, could allow the electricity industry to achieve at least a proportional reduction, and perhaps more, of the state's CO_2 emissions to meet AB 32's 2020 goals"

California has a RPS statute requiring LSEs to achieve 20 percent renewable energy by 2010. There is an Executive order by Governor Schwarzenegger, and legislative proposals, to revise RPS to require 33 percent by 2020. The CEC determines the Net Qualifying Capacity of renewable resources by using formulas established by the CPUC for its jurisdictional entities (matched by California ISO (CAISO)'s tariff requirements for public utilities in its balancing authority area) for determining the capacity contribution of variable resources. CAISO also publishes the monthly wind contribution factors[151] that they use with their resources and has worked to develop solutions to the integration[152] of large amounts of renewable resources within their BA area.

The California Public Utilities Commission (CPUC) has an established a year-ahead and monthly system Resource Adequacy Requirement[153] (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. Direct Control Load Management products are included as resources to meet the LSE's RAR.

The portions of California under the jurisdiction of the CPUC employ a mandatory resource adequacy program requiring LSEs to procure 115 percent of their forecast peak demand for each month. Non-CPUC jurisdictional utilities in the CAISO balancing authority (BA) area are allowed, by CAISO tariff, to set their own planning Reserve Margin values. Although, most use 115 percent also, some do not. The smaller BAs in California have their own planning standards that do not parallel those established collectively for the CAISO BA by the CPUC and CAISO. State entities are working together and with other entities in the Western Interconnection to address transmission planning issues.

Fuel Supply and Delivery
California is highly reliant on gas-fired generation and has very little alternate fuel capability for these plants. In February 2008 the California Energy Commission produced the *2008 Update to the Energy Action Plan (UEAP)*[154] and on page 16 begins to address the natural gas supply, demand, and infrastructure and states they will: 1) Continue to monitor and assess the gas market and its impact on California consumers; 2) Examine whether and how California utilities should enter into contracts for liquefied natural gas (LNG) supplies; 3) Ensure that California has adequate access to those supplies. The UEAP also mentions that there have been proposals for

[150] http://www.energy.ca.gov/2007_energypolicy/index.html
[151] http://www.caiso.com/202f/202f9a882ec90.xls
[152] http://www.caiso.com/1c51/1c51c7946a480.html
[153] http://www.cpuc.ca.gov/PUC/hottopics/1Energy/resourceadquacy/_060824_resourceadequacyletter.htm
[154] http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF

the expansion of gas storage capacities and for a significant expansion of pipeline capacity from the Rocky Mountains to California and that they will be assessing those projects.

Transmission Assessment

With California's new energy policies that require substantial increases in the generation of electricity from renewable energy resources, implementation of these policies will require extensive improvements to California's electric transmission infrastructure. California has developed the Renewable Energy Transmission Initiative (RETI)[155] which is a statewide initiative to help identify the transmission projects needed to accommodate California's renewable energy goals; facilitate transmission corridor designation and facilitate transmission and generation citing permitting.

California – Mexico Projects – Transmission Line Circuit Miles	**AC Voltage (kV)**				
Category	**100-120**	**200-299**	**300-399**	**400-599**	**Total AC**
*Existing as of 12/31/2008	9,745	12,821	351	4,570	27,487
Under Construction as of 1/1/2009	0	273	0	0	273
Planned - Completed within first five years	0	356	0	353	709
Conceptual - Completed within first five years	0	148	0	617	765
Planned - Completed within second five years	0	160	0	0	160
Conceptual - Completed within second five years	0	0	0	2,508	2,508
Total Existing, Under Construction, Planned Line Additions	9,745	13,610	351	4,923	28,628
Total Line Additions	**9,745**	**13,758**	**351**	**8,048**	**31,901**

* The 100 kV class existing is made up of 115 – 161 kV lines, the 200 class was 230-240 kV, the 300 class was 287 - 340 and 345-450 kV classes and 400 - 599 was 500-525 kV classes

As mentioned earlier, with the Arizona Corporation Commission's May 2007 denial of SCE's Palo Verde – Devers #2 (PVD2) permit, in May 2009 Southern California Edison (SCE) dropped the Arizona portion of the proposed line and announced that it would proceed to construct the California portion in 2010. During the years that the line has been proposed the resource situation changed drastically, and SCE now believes that the California portion of the line is useful for central station solar projects being planned for the eastern portion of the state.

Special protection schemes have been implemented for generation connected to the Imperial Valley substation in order to relieve some of the congestion and an operating nomogram is used to limit the simultaneous operation of generating plants connected to the Imperial Valley substation and imports from CFE and Arizona.

Operational Issues

The CAISO has implemented its Market Redesign and Technology Upgrade (MRTU) program, which makes several changes to ISO market and grid operations. The CAISO implemented MRTU April 1, 2009 which includes upgrades to the CAISO's computer technology to a scalable system that can grow and adapt to future system requirements. Transmission upgrades

[155] http://www.energy.ca.gov/reti/index.html

in the area have alleviated some transfer capability limitations, but numerous system constraints remain.

Sacramento Municipal Utility District (SMUD) and LADWP have UVLS schemes. Based on SMUD's 2007 load forecast, 329 MW of UVLS was available. SMUD's UVLS is used as a "safety net" protection scheme used to shed load during extreme system under voltage events. SMUD's reliability assessment meets its reactive margin requirement without relying on UVLS. LADWP's Ten-Year Transmission Assessment identified the use of UVLS to mitigate the effects of the extreme contingency loss of the whole 230 kV Receiving Station E. The plan would selectively shed one load bank in the Hollywood area to mitigate overloads as well as under-voltage conditions. The CAISO only uses UVLS for local area events only.

Over the past decade, the U.S. Environmental Protection Agency is readdressing the Clean Water Act (CWA) Section 316(b) Phase II, which pertains of once-through-cooling (OTC) on existing power plants. The OTC process uses water from a river or ocean for condensing low-pressure steam to water as part of the thermal cycle of these units. In January 2007, the Second Circuit Court issued its decision (Decision) on the Phase II Rule litigation. The result of that Decision was to demand significant portions of the previous EPA 316 b rule back to the EPA. As a result, the EPA withdrew the Phase II Rule in its entirety and directed EPA Regions and states to implement §316(b) on a Best Professional Judgment (BPJ) basis until the litigation issues are resolved. Within the State of California, there are 19 thermal generating plants that use once-through-cooling technology, utilizing large amounts of ocean or estuarial water. Pursuant to the U.S. EPA BPJ directive, the California State Water Resources Control Board (SWRCB) is also considering a proposal[156] that would require these units to stop or greatly reduce the amount of ocean or estuarial water they use in the cooling process in order to minimize the intake and mortality of marine life.

The SWRCB staff plans to release a Substitute Environmental Document (SED) for a proposed statewide policy on once-through-cooling at coastal and estuarine power plants on June 30, 2009 and adopt a formal rule by the end of 2009. The draft SED will include a draft policy, an environmental impacts assessment, a discussion of issues and alternatives, and staff recommendations. According to a public workshop conducted by the Energy Commission on May 11, 2009, the SWRCB-proposed regulation will rely upon an infrastructure development plan prepared jointly by Energy Commission, the California Public Utilities Commission, and CAISO, to ensure the reliability of electric system. Essentially, this approach will assume that most OTC plants will retire, and thus need to be replaced on-site or at locations more remote to load centers via upgraded transmission, rather than refit new cooling technologies onto aging generating facilities. To achieve this major change-out of the electricity generating fleet may take until 2020 to complete.

In February 2008, the CAISO performed an analysis titled "Old Thermal Generation – Phase 1 Report"[157] on the possible impacts of the SWRCB and CEC proposals. CAISO feels a complex technical analysis is needed to fully assess and understand the implications, but the analysis was done to provide a perspective of the interconnected electrical grid in California. Depending on

---

156 http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml
157 http://www.caiso.com/1f80/1f80a4a5568f0.pdf

how the electric system and zonal impacts are handled, they say the risk of shedding firm load could increase four fold.

Eastern Interconnection

FRCC

Introduction

FRCC expects to have adequate generating reserves with transmission system deliverability throughout the ten-year planning horizon. In addition, Existing Other merchant plant capability of 953 MW to 1,337 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 can develop due to unplanned outages of generating units within the FRCC Region. 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

FRCC entities use historical weather databases consisting of 20 years or more of data for the weather assumptions used in their forecasting models. Historically, FRCC has high-demand days in both the summer and winter seasons. However, because the Region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. As such, this report will address the summer load values.

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 Region non-coincident forecast. These individual peak-demand forecasts are coincident for each Load-serving Entitie (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. Resource adequacy is maintained within the FRCC Region by ensuring a minimum 15 percent Reserve Margin to account for higher than expected peak demand due to weather or other uncertainties.

The 2009 ten-year demand forecast for the FRCC Region exhibits a compounded average annual growth rate of 1.8 percent over the next ten years compared to last year's compounded average annual growth rate of 2.1 percent. The decrease in peak-demand forecast growth rate is attributed to an increase in Demand Side Management (DSM) participation as well as higher electricity costs and a decrease in economic development in Florida.

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. The 2009 ten year net internal demand forecast includes the effects of 3,804 MW of potential demand reductions from the use of load management (3,019 MW) and interruptible demand (785 MW) by 2018. Demand response is considered as a demand reduction. Entities within FRCC use different methods to test and verify Direct Load Control (DLC) programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix along with the number of customers participating. Projections also incorporate demand impacts of new energy efficiency programs. There currently is no critical peak pricing with control incorporated into the FRCC projection. Each LSE within FRCC treats every DSM load control program as "demand reduction" and not as a capacity resource.

FRCC projected demand is primarily driven by the variability of weather and economic assumptions. Currently, the FRCC is actively evaluating alternative methodologies to evaluate the potential variability in projected demand due to weather, economic, or other key factors. This year, a weather-normalized hourly load shape curve was developed representing the FRCC Region. In addition, the FRCC is working to develop Regional bandwidths based on historical error of actual versus forecast. The purpose of developing bandwidths on peak demand is to quantify uncertainties of demand at the Regional level. This would include weather and non-weather demand variability such as demographics, economics, and price of fuel and electricity.

Generation

FRCC supply-side resources considered for this ten-year assessment are categorized as Existing (Certain, Other, and Inoperable). The FRCC Region counts on 49,277 MW of Existing Certain resources of which 44 MW are hydro and 474 MW are Biomass[158]. There are a total of 3,747 MW of Existing Other resources identified for 2009 and decreasing to 953 MW by 2018. There are a total of 900 MW of Existing Inoperable resources for 2009 increasing to 1,226 MW by 2018. In addition, there are a net total of 360 MW of Future Planned resources for 2009. By 2018, Future Planned net resources are expected to be 10,778 MW of which 300 MW are categorized as Biomass.

FRCC entities have an obligation to serve and this obligation is reflected within each entity's Ten-Year Site Plan[159] filed annually with the Florida Public Service Commission (FPSC). Therefore, FRCC entities consider all future capacity resources as "Planned" and included in Reserve Margin calculations.

Capacity Transactions on Peak

The FRCC Region does not consider Expected or Provisional purchases or sales as capacity resources in the determination of the Region's Reserve Margin. The expected Firm interregional purchases for 2009 are 2,377 MW and expected to decrease by 2018 to 1,014 MW. 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 members. Presently, the FRCC Region has 143 MW of generation under Firm contract to be

[158] The FRCC Region categorizes the following fuels as Biomass: Agricultural by-products, biogases, straw, energy crops, municipal solid waste, sludge waste, peat, railroad ties, utility poles, wood chips, and other solids.

[159] https://www.frcc.com/Planning/Shared%20Documents/Ten%20Year%20Site%20Plans/2009/2009_TYSPs_ALL_LowRes.pdf

exported during the summer into the Southeastern subregion of SERC throughout 2018. These sales have firm transmission service to ensure deliverability in the SERC Region.

Transmission

Currently, there are 143 miles of transmission under construction as of January 1, 2009. Presently, there are 269 miles of Panned and 70 miles of Conceptual transmission lines identified throughout the 2009 to 2018 planning horizon. At this time, it is expected that the target in-service dates of this transmission will be met. No other significant substation equipment (i.e., SVC, FACTS controllers, HVdc, etc.) additions are expected through 2018.

Transmission constraints in the Central Florida area 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 are planned 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 the Northwest Florida area 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 (Known or Emerging)

There are 398 MW of scheduled generating unit maintenance planned for the summer of 2009 peak period and no generating unit maintenance is planned throughout the 2018 time frame during the seasonal peak periods. No transmission maintenance outages of any significance are scheduled during seasonal peak periods over the forecast horizon. Scheduled transmission outages are typically performed during off seasonal peak periods to minimize any impact to the bulk power system.

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 uncertainties. In addition, there are operational measures available to reduce the peak demand such as the use of Interruptible/Curtailable load, DSM (HVac, Water Heater, and Pool Pump), Voltage Reduction, customer stand-by generation, emergency contracts, and unit emergency capability.

In addition, there are no foreseen environmental or regulatory restrictions that can potentially impact reliability in the FRCC Region throughout the assessment period. No operational changes are needed due to the integration of variable or distributed resources through 2018.

Although Florida is experiencing drought conditions, cooling water levels and water temperature within the FRCC Region are expected to be in the normal range through 2018 and not expected to impact the forecasted Reserve Margin.

Reliability Assessment Analysis

The FPSC requires all Florida utilities to file an annual Ten-Year Site Plan that details how each utility will manage growth for the next decade. Data from the individual plans is aggregated into the FRCC Load and Resource Plan[160] that is produced each year and filed with the FPSC. The FRCC 2009 Load and Resource Plan shows the average FRCC Reserve Margin of 26 percent over the summer peaks and a 39 percent Reserve Margin over the winter peaks for the next ten years. The average winter Reserve Margin is driven by an average 14.7 percent reduction of the forecasted peak demand through 2018. The 15 percent (20 percent for investor owned utilities) Reserve Margin criteria required by the FPSC applies to all ten years of the planning horizon. The calculation of Reserve Margin includes firm imports into the Region and does not include excess merchant generating capacity (Energy-Only) that is not under a firm contract with a LSE. 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.

FRCC has historically used the Loss of Load Probability (LOLP) analysis to confirm the adequacy of reserve levels for peninsular Florida. The LOLP analysis incorporates system generating unit information (e.g., Availability Factors and Forced Outage Rates) 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 conducted in 2009 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 0.1 day per year criterion.

The amount of resources internal to the Region or subregion that are relied on to meet the minimum 15 percent Reserve Margin throughout the assessment period varies from 49,637 MW to 62,465 MW by 2018. The amount of resources external to the Region/subregion that are relied on to meet the Reserve Margin for the assessment period vary from 2,377 MW to 1,014 MW by 2018.

Significant changes affecting the demand forecast include lower population and economic growth and higher energy prices. In addition, the winter demand forecast method was modified to reduce forecasting errors. FRCC is projecting a net increase (i.e., additions less removals) of 10,778 MW of new installed capacity over the next decade, compared to the 15,959 MW projected by last year's ten-year forecast. Of this net increase 8,249 MW are designated for gas-fired operation in either simple-cycle or combined-cycle configurations; 683 MW are anticipated for coal-fired operation; 4,105 MW designated as new and upgraded nuclear; 300 MW are designated as Biomass; and 2,606 MW are related to oil-fired units that have been de-rated, retired; or converted to another fuel type. Gas-fired generation continues to dominate a high percentage of new generation. It is forecasted that electrical energy produced from natural gas generators will increase from 42 percent in 2008 to 47 percent in 2018.

[160] https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/2009%20LRP_Web.pdf

For capacity constraints due to inadequate fuel supply, 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. 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.

Fuel supplies continue to be adequate for the Region and these supplies are not expected to be impacted by extreme weather during peak load conditions. There are no identified fuel availability or supply issues at this time. Based on current fuel diversity, alternate fuel capability and preliminary study results, FRCC does not anticipate any fuel transportation issues affecting capability during peak periods or extreme weather conditions.

Currently there is no Renewable Portfolio Standard in Florida. A draft rule was submitted by the FPSC staff to the Florida Legislature for consideration. However, the Florida Legislature did not establish Renewable Portfolio Standards in Florida. The amount of variable resources within the FRCC Region is so small that these resources have an insignificant impact on resource adequacy assessments. Variable resources within the FRCC Region are typically treated as energy-only. However, some entities may use a coincidence 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 has not identified any unit retirements that could have a significant impact on reliability. The majority of the units in the FRCC Region that are classified to be retired are typically converted and re-powered to run on natural gas.

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 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 BES within the FRCC Region.

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 "FRCC Long Range Study 2009–2018" demonstrating the deliverability of these resources. In order to support the addition of new resources in the 2014 to 2018 time frame, 104 miles of 230 kV and 80 miles of 500 kV transmission additions are needed. Construction of 500 kV transmission lines is considered to be a long lead-time project.

The FRCC Region has approximately 700 MW of load set for Under Voltage Load-Shedding (UVLS) in localized areas to prevent voltage collapse as a result of a contingency event. The UVLS system is designed with multiple steps and time delays to shed only the necessary load to allow for voltage recovery. At this time no additional load is planned to be set for UVLS throughout the planning horizon time period.

Based on past operating experience with hurricane impacts to the fuel supply infrastructure within the Region, FRCC developed a Generating Capacity Shortage Plan[161]. This plan can distinguish between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term, generating fuel; or availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (e.g., hurricanes and abnormally high loads) in order to provide a more effective Regional coordination. The FRCC Operating Committee has also developed the procedure, FRCC Communications Protocols–RC, Generator Operators, and Natural Gas Transportation Service Providers[162], 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 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. The FRCC is not projecting a reduction of total generating capacity (fossil and nuclear) due to low water conditions.

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL 001-004. These studies include long range transmission studies and assessments, sensitivity studies addressing specific issues (e.g., extreme summer weather, off-peak conditions), interconnection and integration studies, and interregional assessments.

The results of the short-term (first five years) study for normal, single, and multiple contingency analysis of the FRCC Region show the thermal and voltage violations occurring in Florida are capable of being managed successfully by operator intervention. Such operator intervention can include generation re-dispatch, system reconfiguration, reactive device control, and transformer tap adjustments. Major additions or changes to the FRCC transmission system are mostly related to expansion in order to serve new demand and therefore, none of these additions or changes would have a significant impact on the reliability of the transmission system.

In addition, the transmission expansion plans representing the longer-term study are typically under review by most transmission owners still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most transmission owners, these projects are not incorporated into the load flow databank

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

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

models. The results show local loading trends throughout the FRCC Region as expected given the uncertainties discussed above. No major projects requiring long lead times were identified.

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 BPS. The "FRCC Long Range Study 2009 to 2018" did not identify any reactive power-limited areas that would impact the BPS through 2018. The FRCC Region has not identified the need to develop specific criteria to establish a voltage stability margin.

FRCC transmission owners evaluate new technologies such as FACTS devices and high-temperature conductors to address specific transmission conditions or issues. Presently, there are several transmission lines constructed with high-temperature conductors within the FRCC Region. At this time there are no FACTS devices installed with the Region. FRCC transmission owners consider enhancements to existing transmission planning tools (e.g., enhancements to existing software, new software, etc.) to address the expected planning needs of the future.

Guidelines for on-site spare generator step-up (GSU) and auto transformers are developed by generator and transmission owners to address specific needs. The FRCC Region does not coordinate or develop spare transformer programs.

FRCC transmission owners have not identified any reliability impacts due to aging infrastructure. Generally, maintenance programs developed and performed by the transmission owners can extend the life of equipment.

Load-serving projects can be delayed, deferred, or cancelled in response to 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 through 2018 due to the degraded economic conditions within the Region.

Other Region-Specific Issues That Were Not Mentioned Above

FRCC is not anticipating any other reliability concerns throughout the ten-year study period. Unexpected potential reliability real-time issues identified by the RC should be resolved with existing operational procedures.

Region Description

FRCC's membership includes 27 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 Electric Reliability Organization, FRCC has registered 70 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

Introduction

The Midwest Reliability Organization (MRO) is a Cross-Border Regional Entity representing the upper Midwest of the United States and a portion of Canada. MRO is organized consistent with the Energy Policy Act of 2005 and the bilateral principles between the United States and Canada.

Sufficient generating capacity is expected within the MRO Region to maintain adequate Reserve Margins through 2018. With Adjusted Conceptual resources included from the generation interconnection queues in the MRO Region, a proxy target Reserve Margin level of 15 percent for the five Planning Authorities is expected to be met through 2018. The Reserve Margin for the MRO-US subregion is met through 2017.

Through the 2018 planning horizon, the MRO expects its transmission system to perform adequately assuming proposed reinforcements are completed on schedule. The MRO Transmission Owners estimate that 833 miles of 500 kV dc circuit, 2,514 miles of 345 kV circuit and 904 miles of 230 kV circuit could be installed in the MRO Region over the next ten years. Continued power market activity will fully utilize the capability of the system, but there may be times when the transmission system may not meet all market needs.

Demand

Each MRO member's peak demand forecast includes factors involving expected economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. Peak demand uncertainty and variability due to extreme weather and 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[163] within MRO utilize a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss of Load Expectation (LOLE) and 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 factor considers uncertainties attributable to weather and economic conditions. From a Regional perspective, there were no significant changes in this year's forecast assumptions in comparison to last year's assumptions.

The MRO Region as a whole is summer peaking. The MRO-U.S. summer peak net internal demand is expected to increase at an average rate of 1.6 percent per year during the 2009 to 2018 period as compared to 1.8 percent predicted last year for the 2008 to 2017 period.

For Saskatchewan, load forecasts (most-likely, low, and high) are developed to cover possible ranges in economic variations and other uncertainties such as weather using a Monte Carlo simulation model to reflect those uncertainties. This model considers each variable to be

---

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

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 a high and low forecast. Quantitative details are provided in SaskPower's annual Load Forecast Report.

The MRO-Canada summer peak net internal demand is expected to increase at an average rate of 1.7 percent per year during the 2009 to 2018 period as compared to 1.3 percent predicted last year for the 2008 to 2017 period. While the MRO Region as a whole is summer-peaking, the MRO-Canada is a winter-peaking subregion. The MRO-Canada winter peak demand is expected to increase at an average rate of 1.7 percent per year during the 2009 to 2018 period as compared to 1.2 percent predicted last year for the 2008 to 2017 period. This increase in load forecast is driven by higher residential load growth due to expected increases in population growth and increases in industrial load due to pipeline expansions, mining, and smelting operations.

The Regional peak load information is non-coincident. MRO staff sends the NERC spreadsheets to each LSE within the MRO Region and requests the relevant data. MRO staff then combines the submitted data in these spreadsheets to acquire an MRO Regional total. MRO staff does not apply a diversity factor to the Regional demand.

Interruptible Demand and Demand Side Management (DSM) programs, presently amounting to approximately 6.3 percent of MRO’s Projected Total Internal Peak Demand, are implemented by a number of MRO members. A wide variety of programs, including direct-load control (such as electric appliance cycling) and interruptible load are used to reduce peak demand. Energy efficiency programs are unidentified at this time. The effectiveness looking out ten years is unknown at this time.

Generation

Existing Resources considered as “Certain” on peak amount to 56,430 MW for 2009. Existing “Other” Resources amount to 5,020 MW for 2009. Existing Inoperable Resources amount to 75 MW. Future Planned Resources for the MRO Region amount to 660 MW starting in 2009 and are estimated to increase to 3,260 MW by 2018. “Conceptual” Resources for the MRO Region amount to 6,630 MW starting in 2009 and are estimated to increase to 15,970 MW by 2018.

Existing wind generation amounts to about 6,000 MW nameplate for summer 2009. Twenty percent of the MRO-US nameplate wind, or about 1,130 MW, is assumed as Certain (available at peak load) and 80 percent is considered as a derate. Although there are no guarantees that variable generation will be available at some predicted value at peak hour, 20 percent is a reasonable assumption based on the historical capacity factors within the Region.

Existing Biomass generation amounts to 350 MW and is estimated to decrease to 282 MW over the next ten years. This generation is typically expected to be available on peak.

For this year’s assessment, NERC has refined the definitions of resources. “Existing” resources are categorized as either “Certain” or “Other.” “Planned” resources are now categorized as “Future” resources, and “Proposed” resources are now categorized as “Conceptual.”

Since the "Conceptual" generation was acquired from the various generation interconnection queues within the Region, a confidence factor was applied by MRO staff to reduce the proposed amount to a realistic expected value. The projects in the interconnection queues were filtered to include only "Active" projects that appeared realistic (many of which has initiated study work or agreements with the Transmission Provider), and a 30 percent confidence factor was applied across all years. This value is judged to be conservative and would not overstate the proposed generation facilities.

The majority of generation in the interconnection queues is proposed wind generation. Much of this wind generation is being proposed within the next three years. At the present time, the Production Tax Credit for wind generation is in effect through 2012.

There are uncertainties involved when using a generation interconnection queue. In-service dates can be deferred. Similarly, some generation that is expected within the next several years may in fact qualify as "Planned" resources. The MRO staff worked with generation owners and the Midwest ISO to verify and update in-service dates of key future generation (i.e., large coal units) and to establish a reasonable confidence factor. When establishing the 30 percent confidence factor, MRO staff also considered the LSEs within the MRO Region have an obligation to serve and are required to meet their obligated Reserve Margins.

SaskPower has a legislated obligation to serve, and as such Future-Planned resources are considered in determining the capacity requirements to meet Saskatchewan's reliability criteria. Future-Planned resources are included based on economically optimized expansion sequences to serve the load.

For the purposes of this assessment, Reserve Margins resulting from Adjusted Conceptual resources will be compared to target Reserve Margin levels.

Purchases and Sales on Peak

For 2009, MRO is projecting total firm purchases of 1,550 MW. These purchases are from sources external to the MRO Region. MRO has projected 970 MW of total sales to load outside of the MRO Region. Both purchases and sales become progressively lower in future years. This is typical, purchases and sales will likely increase as the years approach. By NERC definition, Reserve Margins are to be calculated using the net firm interchange. However, the net import and export of the MRO Region can vary at peak load, depending on system and economic conditions. For example, firm exports may not necessarily be scheduled during internal peak load periods.

Firm transactions from MRO-Canada (Saskatchewan and Manitoba) into the MRO-US are limited to 2,415 MW due to the operating security limits of the two interfaces between these two provinces and the United States. For summer 2009, approximately 1,420 MW of firm transactions from Manitoba Hydro into the MRO-US is expected. The Manitoba Hydro to MRO-US transactions over the ten-year period are contracted firm capacity transactions. Manitoba Hydro native load and contracted export capacity are based on the lowest hydraulic flows on record, delivered over firm transmission service under the Manitoba Hydro Open Access Transmission Tariff. This firm capacity is used in the calculations of the MRO-US and MRO-Canada Reserve Margins throughout the ten-year period.

Throughout the MRO Region, firm transmission service is required for all generation resources that are used to provide firm capacity. This means these firm generation resources are fully deliverable to the load. The MRO is forecast to meet the various Reserve Margin targets without needing to include Energy-only, Uncertain, or transmission-limited resources.

MRO Subregions

Minnesota

Characteristics of System

The Minnesota Area assessment covers the state of Minnesota and a portion of western Wisconsin. The traditional power flow pattern in Minnesota is from the northwest to the southeast and central areas of the state. A major portion of the electric load in Minnesota is concentrated around the Twin Cities metropolitan area of Minneapolis-St. Paul, the principal load center of the Xcel Energy North Control Area. Large power deliveries into the state typically come from Manitoba and the Dakotas due to the hydro resources and the coal-field generation stations. Power typically flows into Wisconsin and Iowa through various 345 kV ties. On occasion, power flows into the Twin Cities area from Iowa primarily when Manitoba is importing power to allow hydro facilities to re-establish their water levels. The characteristics of the grid are changing drastically with wind farm development and their dynamic generation levels. Large wind farm development is expected largely in southern and western Minnesota.

Transmission Additions in Minnesota

The Minnesota Area has multiple transmission additions that will address some of the present constraints although the full impact has yet to be determined. The Minnesota-Wisconsin Stability Interface was replaced with the Minnesota-Wisconsin Exports flowgate, which is comprised of the Arrowhead-Stone Lake 345 kV line and the King-Eau Claire 345 kV line.

The proposed Big Stone Unit II generation project with an on-line date projected for mid-2015 will be building new 230 kV transmission in the western Minnesota area, with some capable of operating at 345 kV, which may have some impact on the North Dakota Export capability as the Big Stone outlet lines will cross the present export boundary. At the same time, transmission companies in the Minnesota Area are jointly pursuing major transmission infrastructure investment through the CapX 2020 effort. This coalition of utilities is seeking to enhance the 345 kV grid for load-serving purposes with facilities available by 2016. The proposed lines will impact multiple flowgates. The proposed Fargo-St. Cloud 345 kV line will impact the North Dakota Export flowgate. The North Dakota Export (NDEX) flowgate will need to be re-evaluated as Big Stone Unit II and CapX projects get further approvals as they move through the permitting process.

The CapX proposed Brookings (SD)-Southeast Twin Cities 345 kV line may also benefit the NDEX flowgate, Lakefield-Lakefield Generation 345 kV line, Fox Lake-Rutland 161 kV line, Rutland-Winnebago 161 kV line, and Lakefield-Fox Lake 161 kV line. The CapX Brookings-Southeast Twin Cities 345 kV line and related underlying projects will support wind outlet in southwestern Minnesota in the order of 1,800 MW.

The CapX proposed Southeast Twin Cities-Rochester-La Crosse 345 kV line will parallel many of the existing constraints in the Region. It is expected that this line will alleviate some of the flowgate issues on the Minnesota-Wisconsin Stability Interface, Prairie Island-Byron 161 kV line, Alma-Wabaco 161 kV line, Silver Lake-Rochester 161 kV line, Cascade Creek-Crosstown 161 kV line, Genoa-Coulee 161 kV line, Genoa-Seneca 161 kV line, Cascade Creek-IBM 161 kV line, Byron-Maple Leaf 161 kV line, Alma-Elk Mound 161 kV line, Adams 345/161 kV transformer, King-Willow River 115 kV line, Red Rock-Glenmont 115 kV line, Genoa-La Crosse Tap 161 kV line, and Adams-Rochester 161 kV line.

A proposed wind farm outlet at Pleasant Valley Station will involve the proposed addition of a 161 kV line between Pleasant Valley Station and Byron. This will create a second 161 kV loop between Byron and Adams 345 kV substations, thus potentially relieving the Byron-Maple Leaf 161 kV line, Cascade Creek-Crosstown 161 kV line, Cascade Creek-IBM 161 kV line, Silver Lake-Rochester 161 kV line, and Adams-Rochester 161 kV line. This proposed line is not expected to be in service until at least 2010.

The studies performed for the Minnesota show the existing and planned transmission system in the area can operate at all load levels respecting unscheduled contingencies, while meeting the relevant voltage and loading criteria without causing cascading, service interruptions, or instability. In the short term, there are operating guides to govern the operation of the transmission system to ensure the reliability such that violations do not occur in the interim period until new facilities can be permitted and put into service. The CapX projects will enhance the transmission in the Minnesota whereby many of the concerns will be eliminated.

Nebraska

Characteristics of System

The Nebraska transmission network can be divided into two distinct Regions for reliability: the eastern Region and the western Region. Presently, the electrical division between these two Regions involves the transmission systems on either side of the Grand Island/Hastings area. Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) currently post six constrained paths located within or adjacent to the NPPD and OPPD control areas.

Transmission Additions for Nebraska

<u>Grand Island 345/230 kV New Transformer</u>
Western Area Power Administration (WAPA) and NPPD completed a joint-planning study to address the contingency-loading issues associated with the existing two 250 MVA 345/230 kV Grand Island transformers. The recommended transmission facility plan is to install a third 345/230 kV transformer at the Grand Island Substation. WAPA and NPPD are planning to have this new transformer in-service by the summer of 2009.

<u>North Platte 230/115 kV New Transformers</u>
Past studies had identified potential overloads of the two 187 MVA 230/115 kV transformers at the NPPD North Platte Substation for single contingencies during summer-peak load conditions. Studies also showed that during heavy transfer conditions, both transformers could overload for a double circuit 345 kV contingency. To address these issues, NPPD plans on replacing both 187

MVA units with new 336 MVA units. The first North Platte 230/115 kV transformer was replaced in spring of 2007 and the second unit is planned for replacement in 2010.

Columbus ADM Load Expansion and Co-Gen Project
The ADM (Archer Daniel Midlands Company) ethanol plant expansion project at their existing Columbus location is currently under construction. The project involves the development of a new dry mill ethanol plant facility and addition of 75 MW of new load. Along with this ethanol plant, a new 75 MW coal-fired Co-Gen generating facility will be developed to provide auxiliary steam for the ethanol plant. To accommodate the new dry mill plant and co-gen facilities, a new 115 kV transmission interconnection is being developed. The new ADM Interconnection substation and 115 kV facilities are currently planned for a June 2009 in-service date. The Columbus ADM Co-Gen facility is currently planned for a December 2009 in-service date.

Norfolk / Columbus / Lincoln 345 kV Transmission Project
Due to rapid load growth in the east central Nebraska Region, there are system intact and single contingency voltage issues projected for future summer peak load conditions. Numerous transmission expansion alternatives were evaluated to address the voltage depression issues. As a result of this study work, the Columbus and Norfolk Transmission Expansion Plan was recommended to address the summer-peak load voltage issues and enhance the reliability of the eastern Nebraska regional transmission system. The Electric Transmission Reliability (ETR) for East-Central Nebraska 345 kV Transmission Expansion Plan is targeted for completion by 2010.

Phase 1 of the ETR Project was energized in June 2008. Phase 2 of the ETR Project includes the construction of a new 345 kV transmission line from Shell Creek to Columbus East to LES NW 68th and Holdrege and the expansion of the Columbus East 345/230/115 kV Substation is currently expected to be completed by December 2009.

Whelan Energy Center 2
The Public Power Generation Agency (PPGA) has construction underway for a second coal-fired generating unit at the Whelan Energy Center Station. Whelan Energy Center Unit 2 (WEC2) is expected to begin commercial operation by spring of 2011 with a nominal net output of 220 MW.

Nebraska City Unit 2 and Transmission Expansion Plan
The Omaha Public Power District (OPPD) is constructing a second coal-fired generating unit at the Nebraska City Power Station. Nebraska City Unit 2 (NC2) is expected to begin commercial operation in June of 2009. The NC2 Transmission Planning Group developed an expansion plan to accommodate the interconnection and delivery of NC2.

Wagener-NW68th and Holdrege 345 kV line
This project includes construction of a 26-mile 345 kV line from the Wagener Substation to the NW68th and Holdrege Substation, around the northern perimeter of Lincoln. This 345 kV line was committed to by LES as part of the Nebraska City Unit 2 transmission plan.

Knoll - Axtell 345 kV line
This project includes construction of a 345 kV interregional tie line from Knoll to Axtell Substations. Approximately 35 miles are included within Nebraska.

NW68th and Holdrege Transformer Addition
A second 345/115 kV transformer at the NW68th and Holdrege Substation is planned with an in-service date of 2013.

The existing and planned transmission system in the Nebraska Area can operate at all load levels respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, service interruptions, or instability.

The Dakotas

Characteristics of System

The electrical system in Eastern Montana and the Dakotas consists of Investor-Owned Utilities, Cooperatives, Municipalities, and Federal facilities. Dakotas area voltage ranges are mostly 345, 230, 161 and 115 kV, although there are some 500 kV facilities operated at 345 kV. Projects under study for the Dakotas and eastern Montana include wind generation facilities and coal-fired generation facilities during the next ten-year period. New combustion turbine generators for use as peaking units are also under study. The Dakotas and eastern Montana are a net exporter of energy. Significant generation is derived from hydroelectric and coal-fired thermal facilities.

Renewable Generation and Associated Facilities

Requests are pending on 14,959 MW of queued projects for wind generation with another 1,279 MW already under study. Wind generation typically has a very fast planning and construction period, and it is anticipated that wind generation will continue to be installed in the Dakotas.

Network and Load Associated Facilities

Facility additions are scheduled for the 2009 to 2014 time period. Facility additions include new substation equipment such as capacitor bank additions and transformers, and high voltage transmission line additions. Unexpected load growth in the oil fields and coal bed methane fields has led to a large increase in load in some isolated areas. This unexpected load growth has resulted in individual substation loads that were projected to be less than 10 MW in the 2003 to 2004 timeframe are now approaching 100 MW. Constructing the facilities to handle this growth is on a fast track, but the long-term transmission improvements will require significant lead time.

Constraints

Several projects in the Sheyenne-Fargo area are planned to address transmission limits. The next most limiting constraint is in the Tioga (North Dakota) area in which projects are in the active construction phase.

The existing and planned transmission system in the Dakota Area can operate at all load levels respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, service interruptions, or instability. In the short-term, operating guides govern the operation of the transmission system to ensure reliability violations do not occur in the interim period until new facilities can be permitted, constructed and put into service.

Iowa

Characteristics of System

The Iowa electric transmission system is comprised mainly of 345, 161 and 115 kV transmission facilities. The Iowa electric system continues to see a confluence of new spot loads, a large amount of new wind farm installations, and a large number of different power schedules in various directions. All of these items contribute to a varied flow pattern throughout Iowa. In general, the state has a reasonable number of baseload power plants distributed throughout the state and has been building a reasonable amount of new transmission to accommodate new generation and load installations. The distribution of baseload power, short transmission lines, and new transmission to accommodate new generation have all contributed towards a more stable and higher capacity grid.

Significant Proposed Transmission

- Upgrade of the Salem 345/161 kV transformer. This project is planned for 2009.
- Upgrade of Hazleton 345/161 kV transformer #1. This project is planned for 2011.
- A Salem–Hazelton 345 kV line and adding a second 345/161 kV transformer at Salem. This project is planned for 2011.
- A Morgan Valley 345/161 kV Substation between the Tiffin and Arnold 345 kV Substations. A new 161 kV line is proposed between Morgan Valley and Beverly 161 kV Substations. The project is proposed for 2012.

The existing and planned transmission facilities in the Iowa can operate at all load levels with existing and future committed firm transfers while meeting thermal, voltage, and dynamic criteria. The Iowa system is beginning to experience the confluence of several Regional forces including an increase in installed wind power in Minnesota, northern Iowa, and central Illinois, new Missouri River baseload generation capacity near Council Bluffs and Nebraska City (2009), and the development of several new spot loads. Power from wind and coal in western Iowa (and Nebraska) should decrease east–west transfers, while future additional Illinois wind power could again reinforce east–west and possibly south–north transfers. The three increasing impacts of wind, coal, and load will continue to require some new transmission to adequately meet NERC criteria.

Wisconsin

Characteristics of System

Southern Tie Interface

The Southern Tie interface consists of the Wempletown–Paddock 345 kV line, Wempletown – Rockdale 345 kV line, Zion–Lakeview 138 kV line, Zion–Arcadian 345 kV line, and Zion – Pleasant Prairie 345 kV line. This interface is thermally limited for critical N–1 contingencies and voltage–stability constrained for critical N–2 contingencies during heavy imports across the interface. Operating guide including coordinated reciprocal flowgates of the Midwest ISO and Pennsylvania–New Jersey–Maryland (PJM), are used to monitor and manage these constraints. Daily voltage–stability studies are performed by the Midwest ISO and the American Transmission Company (ATCLLC) to establish voltage-stability limits for the Southern Tie interface. The completion of the second Paddock–Rockdale 345 kV line in 2009 helps alleviate these constraints.

Minnesota Wisconsin Export Interface (MWEX)
This interface consists of the King–Eau Claire 345 kV line and the Arrowhead–Stone Lake 345 kV line. During high imports from Minnesota into WUMS across the MWEX interface, the system is susceptible to a transient voltage recovery violation and voltage instability under critical N-1 and N-2 contingencies. Operating guides, including coordinated reciprocal flowgates of the Midwest ISO and MAPP, are used to monitor and manage these constraints. Daily voltage stability studies are performed by the Midwest ISO and ATCLLC to establish voltage stability limits for the MWEX interface.

Flow South Interface
The Flow South interface consists of the Morgan–Plains 345 kV line, Stiles–Amberg 138 kV line, Stiles–Crivitz 138 kV line, Ingalls–Holmes 138 kV line, and Cranberry–Lakota Rd 115 kV line. The system is susceptible to voltage instability under critical N-1 contingencies during heavy flows from the northeast Wisconsin into Upper Peninsula of Michigan (UP) across the interface. The operating guide is in place to manage the congestion on the Flow South interface. Further, during the increased transfers from Wisconsin to UP, prior to approaching the Flow South interface voltage-stability limits, there is a potential for thermal overload on the Pulliam – Stiles 138 kV and White Clay–Morgan 138 kV lines under critical N-1 and N-2 contingencies. Operating guide is in place to manage these contingent thermal violations. The completion of the Werner West–Highway 22–Morgan and Gardner Park–Highway 22 345 kV lines in 2009 helps alleviate these constraints.

West to East UP Interface
This interface consists of the Indian Lake 138/69 kV transformers T1 and T2. During typical night-time load conditions, when the Ludington generating/pumping station in lower Michigan is in pumping mode combined with increased west to east Regional system flow bias, higher west to east transfers in UP across the interface may occur. This may cause thermal overload and low voltage conditions under critical N-1 contingencies. The operating guide that manages these constraints calls for splitting the UP when the system operating limits are being approached. The transmission plans under development at ATCLLC through the UP Collaborative initiative will help alleviate these constraints.

East to West Upper Peninsula Interface
This interface consists of the double-circuit Straits-McGulpin 138 kV lines. During typical day-time load conditions, when the Ludington generating/pumping station in lower Michigan is in generating mode combined with increased east to west regional system flow bias, higher east to west transfers across the interface into UP may occur. This may cause thermal overload and low voltage conditions under critical N-1 contingencies. The operating guide that manages these constraints calls for splitting the UP when the system operating limits are being approached. The transmission plans under development at ATCLLC through the UP Collaborative initiative will help alleviate these constraints.

Canada Sub-Region
The Canadian area of MRO consists of the Manitoba Hydro (MH) and SaskPower (SP) systems. The Manitoba system is synchronously interconnected to the SP system to the west via three 230 kV lines and two 115 kV lines and to the Ontario Hydro Networks Company (OHNC) system to the east with two phase-shifted 230 kV lines. The SaskPower system has a back-to-back HVdc link with the province of Alberta to the west. To the south, the Canadian-area system is tied with

the MRO-US system through a 500 kV line and three 230 kV lines, a phase-shifted 230 kV line, and a phase-shifted 115 kV line.

Characteristics of Manitoba System

The MH system has approximately 5,500 MW of total generation. The system is characterized by approximately 3,600 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via two HVdc links, specifically two 550-mile HVdc transmission lines designated as Bipole 1 and Bipole 2. MH also has about 1,450 MW of hydraulic generation and 480 MW of thermal generation distributed throughout the Province. Manitoba Hydro has one 99 MW wind farm in-service. Manitoba Hydro plans to add a new hydraulic generating station in northern Manitoba in 2012 called Wuskwatim capable of 200 MW. The new generation and associated transmission facilities required to integrate the proposed generator into the Manitoba Hydro system will significantly improve the reliability of the northern AC system.

The MH hydraulic system generation is planned based on dependable river flows based on the lowest water flow conditions on record in order to meet firm winter-peak load and firm export contracts. Consequently, during periods of normal or above normal river flows, large amounts of surplus energy are available for export on a short-term or seasonal basis. Conversely, MH may import power during extended periods of drought conditions resulting in low water conditions.

Transmission Additions in Manitoba

The following projects are now underway or planned in the next decade and will maintain the transmission system operating performance requirements in the future. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads in Manitoba and transmit generation to the export market. Other drivers of expansion are to improve safety, increase efficiency, and connect new generation. Not all proposed projects will be built. Some may be dropped or refined to reflect changing circumstances.

Wuskwatim Generation Outlet Facilities consist of 296 miles of 230 kV transmission to interconnect the new 223 MW hydro generating plant into the Manitoba northern ac grid.

The new 500/230 kV Riel Station consists of a new station, which will include:

- Installing a 230 kV to 500 kV transformer bank
- Sectionalizing the existing Dorsey–Forbes 500 kV line
- Sectionalizing two existing 230 kV lines (Ridgeway–St. Vital lines R32V and R33V)
- Bipole III transmission from Conawapa Station in the north to Riel Station near Winnipeg. The Bipole III HVdc and its link to the west side of the province includes:
- ±500 kV HVdc transmission line, about 833 miles long, from Conawapa Converter Station to Riel Converter Station
- 2,000 MW converter station at Conawapa
- 5 AC transmission lines each approximately 19 miles in length to connect the Conawapa Converter Station to the northern collector system
- 2,000 MW converter station at Riel, including four synchronous compensators
- Part of the Winnipeg to Brandon improvements includes the addition of a new 43.5 mile 230 kV line from Dorsey to Portage South.

Several new 230/115 kV and 66 kV transformers are being added to the system. The sites include Rosser, Transcona, Stanley, and Neepawa stations.

Rosser-Parkdale-Selkirk 115 kV Transmission System project consists of development of a new 230/115 kV Rockwood Station supplied from sectionalized Ashern to Rosser 230 kV transmission line A3R. A 230/115 kV transformer and associated structural and electrical apparatus will be needed to connect this new station to the existing 115 kV system.

Scotland Station Rebuild is required in order to provide additional capacity to the core Winnipeg area and facilitate the replacement of aging equipment at Scotland Station. The Scotland 138 kV and 115 kV–66 kV Terminal Station is going to be rebuilt. This will involve salvaging four 138/66 kV transformer, two 115/66 kV transformers, installing two new 125 MVA 115/66 kV transformer, and new 66 kV and 115 kV ring buses. In addition, the 138 kV transmission system between Pointe Du Bois, Slave Falls, and Scotland will be converted to 115 kV so that the former Winnipeg Hydro transmission can be integrated into the Manitoba Hydro 115 kV system. Pointe Du Bois 138/66 kV Bank 7 will be replaced by a new 115/66 kV 60 MVA bank to accommodate the voltage conversion. Finally, line HS5 from Harrow to Scotland will be reconductored with 336 ACSS conductor and the 115 kV ring bus at Harrow Station will also be upgraded.

The existing and planned transmission system in the Manitoba Hydro Area can operate at all load levels and firm transfers respecting unscheduled contingencies while meeting the relevant voltage and loading criteria without causing cascading, firm service interruptions, or instability.

Saskatchewan

Saskatchewan is a prairie province of Canada and comprises a geographic area of 651,900 square km and approximately one million people with peak demand occurring in the winter. The Saskatchewan transmission system is characterized by relatively long 230 kV and 138 kV transmission lines connecting dispersed generating stations to sparsely distributed load supply points. Networked transmission facilities are operated at the 230 kV and 138 kV voltage levels.

Saskatchewan has transmission interconnections with the provinces of Alberta and Manitoba, and the U.S. state of North Dakota. Some of the additions include:

- Addition of a 100-mile 230 kV transmission line and 230/138 kV MVA auto-transformer in south-central Saskatchewan in 2010 to mitigate post-contingency overloads and voltage support in the area.
- Addition of a 55-mile 230 kV transmission line in central Saskatchewan in 2012 to meet transmission adequacy in the area for customer load growth.
- Addition of a 62-mile 230 kV transmission line and 230/138 kV MVA auto-transformer in eastern Saskatchewan in 2012 to meet transmission adequacy in the area for customer load growth.
- Addition of a 37-mile 230 kV transmission line in south-central Saskatchewan in 2012 to meet transmission adequacy in the area for customer load growth.
- Addition of a 200 Mvar SVS in south-central Saskatchewan will be installed in 2010 to provide post-contingency voltage support in the area.

At this time there are no major concerns in meeting targeted in-service dates.

Operational Issues

There are no known outages that will impact reliability at this time. 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.

It has been observed that the rapid increase or decrease of wind generation in Iowa and Minnesota can have significant impact on the flows through the Wisconsin Upper Michigan Systems (WUMS) western and southern interfaces, namely Minnesota Wisconsin Export (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 a monitored Flowgate reaching 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.

Operational issues in general regarding wind generation have been identified in the *MRO 2009 Scenario Assessment. NERC's Special Report: Accommodating High Levels of Variable Generation*[164] can be referenced for more information.

There are no known operational concerns resulting from generation connected to the distribution system.

The onset of CO_2 regulations as well as the requirement to reduce Critical Air Contaminants such as SO_2 and NO_x could cause restrictions to high-emitting technologies. The magnitude is unknown at this time.

Reliability Assessment Analysis

The MRO Reliability Assessment Committee is responsible for the long-term reliability assessments. The MRO Transmission Assessment Subcommittee, MRO Resource Assessment Subcommittee, the MAPP Transmission Planning Subcommittee and its Transmission Reliability Assessment Working Group (TRAWG), the ATCLLC, and SaskPower all contribute to this MRO Long Term Reliability Assessment.

The MRO Region is composed of several Planning Authorities, each with a distinct Reserve Margin target. The MAPP Generation Reserve Sharing Pool (GRSP) requires a 15 percent reserve capacity obligation for predominantly thermal systems, and 10 percent reserve capacity obligation for predominantly hydro systems, based on previously conducted LOLE studies. On December 2, 2008, MAPP members approved the 2009–2018 MAPP LOLE Study Report. This report is posted at: www.mapp.org. Approximately 8,850 MW of existing generation in the

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

MAPP GRSP (16 percent of MRO net internal capacity) is associated with predominantly hydro systems and only requires a 10 percent reserve capacity obligation.

The Midwest ISO has conducted a Loss of Load study establishing a 12.7 percent Reserve Margin requirement for all Midwest ISO LSEs. Also, the Midwest ISO began operation of its Ancillary Services Market (ASM) on January 6, 2009, which included operation as a single Balancing Authority.[165]

For former MAIN members now within MRO who do not belong to the MAPP GRSP, generation resource adequacy is assessed based on LOLE studies previously conducted by the previous MAIN Region. Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum long-term planning Reserve Margin of 16 percent.

Saskatchewan's reliability criterion is based on annual expected unserved energy analysis (EUE) and equates to an approximate 15 percent Reserve Margin requirement.

For the purpose of this assessment, MRO would typically use a 15 percent Region-wide Reserve Margin as a proxy measure of adequacy, which is representative of the range of Reserve Margin targets for the various groups within the MRO.

Also for the purposes of this assessment, the Adjusted Conceptual resources—Conceptual resources after they have been appropriately adjusted by a confidence factor—is used in the calculation of the forecasted Reserve Margins. Several of these Conceptual projects, particularly those with near-term in-service dates, may already be in the Planned project status.

MRO total — When using Adjusted Conceptual resources, the Reserve Margins for the full MRO Region range from 23.4 percent to 18.2 percent for the 2009 to 2018 period. All 10 years exceed the target Reserve Margin of 15 percent. These values are based on summer peak.

MRO-US — When using Adjusted Conceptual resources, the Reserve Margins for the MRO-US subregion range from 23.7 percent to 14.3 percent for the 2009 – 2018 period. The first nine of 10 years exceed the target Reserve Margin of 15 percent. These values are based on summer peak.

MRO-Canada — When using Adjusted Conceptual resources, the Capacity Margins for the MRO-Canada subregion range from 21.4 percent to 44.5 percent for the 2009 to 2018 period. All 10 years exceed the target Reserve Margin of 15 percent. These values are based on summer peak. For winter peak, the MRO-Canada margins range from 21.3 percent to 25.7 percent for the 2009 to 2018 period, which also exceed the target Reserve Margin of 15 percent.

Saskatchewan does not rely on emergency imports, reserve sharing, or external resources other than a 50 MW firm purchase for the 2009/2010 and 2010/2011 winter seasons.

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

Most of the MRO Reserve Margins do not vary based on short-term versus long-term. However, the former MAIN members now within MRO use a minimum long-term planning Reserve Margin of 16 percent, and a minimum short-term planning Reserve Margin of 14 percent.

Saskatchewan is adding up to 400 MW of simple cycle natural gas-fired combustion turbines over the next four to five years. Additional capacity that will be required in the last five years of the reporting ten-year period is currently being evaluated.

Resource unavailability would be offset by planning reserves and external markets. If and when necessary, operational measures which include emergency plans, interruptible load contracts, public appeals, and rotating outages, would be implemented.

Saskatchewan does not anticipate any fuel delivery problems. Fuel-supply interruption in Saskatchewan is generally not considered an issue due to system design and operating practices.

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. SaskPower has 20 days of on-site stockpile for each of its coal facilities (Poplar River, Boundary Dam, and Shand). Strip coal reserves are also available and only need to be loaded and hauled from the mine. Poplar River has a 65 day reserve, and Boundary Dam and Shand have a 30 day reserve. In addition:

- Natural gas resources have firm transportation contracts with large natural gas storage facilities located with the province backing those contracts up.
- Hydro facilities and reservoirs are fully controlled by SaskPower.
- Typically Saskatchewan does not rely on external generation resources.

The MRO Region does not count on energy-only or transmission-limited resources for reliability purposes.

Renewable Portfolio Standards, per the U.S. Department of Energy's web site (excludes Canadian provinces) are shown in the table below. In this table, the 105 MW listed for Iowa is applicable to only two Iowa utilities, MidAmerican Energy Company (55.2 MW) and Interstate Power and Light Company (49.8 MW). North Dakota and South Dakota have renewable objectives, which are similar to RPS, except they are not mandates.

Table MRO 1: Renewable Portfolio Standards Per US Department of Energy

State/Province:	Amount (percent 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	

Variable resources are not considered in SaskPower's resource adequacy assessment. However, SaskPower is currently reviewing a capacity credit for wind.

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.

The reliability impact due to retirement of generating units in the MAPP Planning Authority footprint is evaluated by the MAPP Design Review Subcommittee in coordination with generation and transmission owners.

Saskatchewan has planned unit retirements over the next ten years that have been included in the reliability assessment. Unit retirements are offset by unit additions in Saskatchewan's Supply Plan.

Generation deliverability is 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/
http://oasis.midwestiso.org/OASIS/MHEB
https://www.oatioasis.com/spc/

In general, transmission providers within MRO ensure deliverability of resources at the time of system peak through ongoing operating and planning studies. These studies ensure resources can be delivered to load under normal and various worst case generation dispatch and power transfer scenarios without being constrained at peak load.

Throughout the MRO Region, firm transmission service is required for all generation resources that are utilized to provide firm capacity. This means these firm generation resources are fully deliverable to the load. 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.

No specific analysis was performed by MRO to evaluate whether external resources are available and deliverable. However, 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.

Saskatchewan ensures external resources are deliverable by performing joint operational planning studies with Manitoba for the MRO-Canada Region to define transfer capability for Saskatchewan. The studies define secure transfer capabilities and operational requirements for the season. Studies consider simultaneous transfers to and from Manitoba and North Dakota and any known transmission and generation issues.

The proposed Big Stone Unit II generation project with an on-line date projected for 2015 will require new 230 kV transmission in the western Minnesota area. Some of this new transmission may be capable of operating at 345 kV.

Transmission in the Dakotas and Minnesota is not capable of delivering the wind generation that is presently in the MISO generation interconnection queue. The CapX 345 kV line from Brookings, South Dakota to the Twin Cities is in the Minnesota certificate-of-need process and is being constructed to support additional wind generation and other potential resources and also to support load serving needs. Portions of this line are expected to be completed in the 2011 to 2015 timeframe.

Governors of the five states (North Dakota, South Dakota, Minnesota, Iowa, and Wisconsin) announced the Upper Midwest Transmission Development Initiative (UMTDI) in September 2008. The goal of this initiative is to establish a plan that will guide and encourage the construction of interstate transmission to serve the states' commitment to cost-effective renewable generation while maintaining reliability. A major input that supports this effort has been the Regional Generation Outlet Study (RGOS) organized by the Midwest ISO. This study investigates the future transmission plans needed to serve the states' existing Renewable Energy Standards (RES) requirements and beyond. Transmission owners, utilities and other stakeholders in the five states have been actively participating and providing input to both the UMTDI and RGOS efforts. Study results that support the UMTDI effort will become available in October 2009 and are not available for sharing at this time. However these efforts are considered worth noting for this assessment.

A transmission project to transport the renewable energy from the wind-rich Plains states to major metropolitan markets, the Green Power Express, was announced in February 2009. This project would be a 12,000 MW 765 kV transmission line, running approximately 3,000 miles through North Dakota, South Dakota, Iowa, Wisconsin, Minnesota, Illinois and Indiana. It would consist of three interconnected loops in North Dakota, South Dakota, Minnesota, and Iowa, with extensions from these loops into Wisconsin, Illinois, and Indiana. The transmission line would interconnect with existing lower-voltage transmission facilities, similar to on and off-ramps on an interstate highway. The transmission project would enable development of the wind energy potential in North Dakota, South Dakota, and Iowa, which currently is severely limited by the lack of transmission capacity. The Green Power Express would be the first transmission line that is intended to provide transmission to markets for wind developers in these areas.

Saskatchewan currently has no major transmission additions planned specifically to support the addition of new resources or imports. Saskatchewan is currently in the process of evaluating baseload resource additions over the next six to ten years and the associated transmission. Once these options have been evaluated and major transmission additions may be required.

Several members within the MRO Region have localized UVLS programs to prevent localized low voltage conditions. These programs are not required to protect the BPS.

Emergency conditions within the MRO Region would be managed through the Reliability Coordinators. Resource and/or transmission deficiencies would be offset by planning reserves and external markets. If necessary, operational measures, which would include emergency plans, interruptible load contracts, public appeals, and rotating outages, would be implemented as necessary.

Water levels in the MRO-US are adequate to meet Reserve Margin needs. However, from an energy perspective, reservoir water levels throughout the northern MRO-US 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 Manitoba Hydro generation is planned to be adequate to supply Manitoba load and contracted firm export based on the lowest hydraulic flows on record (worst drought experienced in Manitoba). Delivery of the generation required to serve load and firm exports is connected as a Network Resource ensuring delivery under Manitoba Hydro's Open Access Transmission Tariff (OATT). The contracted firm exports are delivered via firm point-to-point transmission service under the OATT.

ATCLLC does not own any generator step up (GSU) transformers but owns many medium and large auto transformers. Many sites have dedicated spare units and system spares are stored at strategic locations. On-site spares are determined on a case-by-case basis. ATCLLC participates in the EEI Spare Transformer Emergency Program (STEP).

Manitoba Hydro planning criteria requires the installation of sufficient capacity to supply station load following the loss of on parallel transformer. Manitoba Hydro has spare phase unit for it large 500–230 kV single-phase autotransformers. In addition, Manitoba Hydro has a system spare for its 230–66 kV transformers.

Saskatchewan does not have a guideline for spare GSU transformers; however they currently have a system spare GSU to share amongst their major base load coal units. The planning guideline for autotransformers is to have enough installed capacity so that one may be used as a system spare. Saskatchewan does not participate in any program to share spare transformers.

The MAPP Planning Authority does not have guidelines for sharing of transformers. If circumstances allow, TOs are willing to accommodate to the extent that the action doesn't impact the lending TOs reliability or construction plans.

For the rest of the MRO Region, the need for spare transformers is decided on a case-by-case basis.

A Reliability Assessment Study is performed annually by the MAPP Transmission Reliability Assessment Working Group (TRAWG). NERC Category A (system intact), NERC Category B, and some NERC Category C and known multiple element single contingencies outages (such as common tower) are performed according to NERC criteria. A number of NERC Category D contingencies were also evaluated. Assessments are done on model years 2009, 2014, and 2019 for winter peak, summer peak and summer off peak, high transfer conditions. Dynamic analysis was done on 2009, 2014, and 2019 for winter peak and summer off peak high transfer models. The transmission system is expected to perform reliably throughout the analysis period.

ATCLLC performs annual ten year planning studies to ensure reliability in planning horizon (Reference 1). ATCLLC performs an annual summer assessment study and also participates in the Midwest ISO summer and winter seasonable assessment studies. The objectives of these operational studies are to provide system operators with guidance as to possible system conditions that would warrant close observation to ensure system security (References 2, 3).

Manitoba Hydro performs ongoing system planning studies ranging over the ten year planning horizon to assess and enhance reliability, integrate new generation, address forecast load growth, connect new large industrial load and facilitate transmission service requests. Manitoba Hydro publishes a ten-year Plan annually, which is posted on its website (http://oasis.midwestiso.org/OASIS/MHEB).

Saskatchewan performs ongoing transmission planning studies to integrate new generation and load and assess reliability, and there are ongoing infrastructure improvements being developed to address any issues identified.

The MRO Region presently uses Special Protection Systems (SPS) to maintain reliability and allow the owners to meet TPL-001, TPL-002, and TPL-003 Standards per NERC Standard PRC-012. Certain MRO members also utilize SPSs to meet TPL-004 as well.

Saskatchewan uses a guideline of five to 10 percent (away from the nose of the P-V curve). Saskatchewan does not typically evaluate voltage stability margins in its operating and planning studies unless there is an identified need.

A voltage stability study was done for the majority of the MRO Region (excluding Saskatchewan and WUMs) and was published in 2005. The study found no single contingency that resulted in system collapse or cascading.

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 ten-year assessment studies (Reference 1) to ensure reliability.

ATCLLC expects to continue the deployment of the following technologies and analytical software tools to improve BPS reliability that are not widely used in the industry: Distributed Superconducting Magnetic Energy Storage Devices (DSMES), certain High Temperature Low Sag (HTLS) conductors, and software tools such as Physical and Operational Margins/Optimum Mitigation (POM/OPM), Production Cost Modeling (PROMOD), Voltage Stability Analysis

Tool (VSAT), and Power World. In addition, ATC participates in the review and development of new technologies, systems, and tools through Electric Power Research Institute, Power Systems Engineering Research Center, and CEATI International Inc. research activities.

Companies within MRO have asset-renewal programs to invest in transmission infrastructure and replace aging infrastructure before it degrades reliability. Several companies have reliability-centered maintenance programs. This is considered a good utility practice.

There are no known reliability impacts resulting from project slow-downs, deferrals, or cancellations within the Region.

Other Region-specific issues that were not mentioned above:

Because wind generation is a variable resource, the operational impacts of the large amount of proposed wind generation in the MRO Region will need to be closely monitored for any reliability impacts. The impact of wind generation is discussed in more detail in the MRO Scenario Assessment. This report was provided to NERC in July 2009.

Region Description

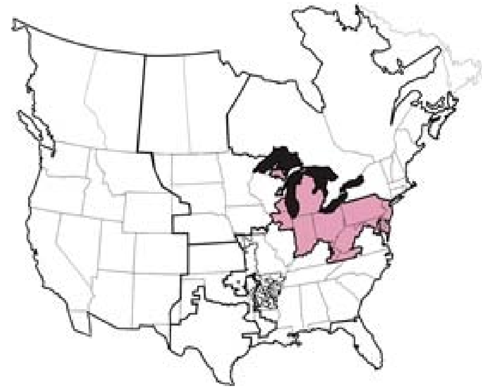
The Midwest Reliability Organization (MRO) has 48 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant and Transmission System Operator. The MRO has 19 Balancing Authorities and 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.

Reference Documents:

1. 2008 — ATCLLC 10-Year Transmission System Assessment Update, http://www.atc10yearplan.com
2. Midwest ISO Summer 2009 Coordinated Seasonal Transmission Assessment, on-going, http://www.midwestiso.org/home
3. ATCLLC 2009 Operations Summer Assessment, on-going
4. SaskPower 2008 Supply Development Plan
5. SaskPower 2009 Load Forecast Report
6. SaskPower NERC Long Term Reliability Assessment Data Reporting Form ERO-2009 Long-Term Reliability Assessment
7. SaskPower 2008 and 2009 Planning Studies
8. Manitoba Hydro - Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability
9. *http://www.mapp.org/content/policies.shtml*
10. 2009_MAPP_System_Performance_Assessment_Summary
11. MAPP 10-Year Transmission Assessment

RFC

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 a member of either RTO and is not affiliated with their markets; however, OVEC's Reliability Coordinator services are performed by PJM. Also, MISO began operation of its Ancillary Services Market (ASM) on January 6, 2009 which included operation as a single Balancing Authority.[166]

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 projected resource adequacy 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. [167] 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 *Long-Term Reliability Assessment* focuses on three factors, Total Internal Demand (TID), Net Internal Demand (NID), and Demand Response.

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 the weather being cooler and a 50 percent chance of the weather being warmer than the forecast). The Reliability*First* Region identifies the various programs and contracts designed to reduce system demand during the peak periods as Demand Response. Individual companies may implement Demand Response through a direct-controlled load program, an interruptible load contract or other contractual load reduction arrangement. Since Demand Response is a contractual management of system demand, utilization of Demand Response reduces the Reserve Margin

[166] More information is available at http://www.midwestmarket.org/publish/Folder/469a41_10a26fa6c1e_-741b0a48324a.
[167] http://www.rfirst.org/Documents/Standards/Approved/BAL-502-RFC-02.pdf

requirement for the RTO. Net internal demand is total internal demand less Demand Response. 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. Demand Response 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 this long term assessment, the RTOs within Reliability*First* have identified the following types of Demand Response programs:

Direct Control 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 hot 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 (NID) peak of the entire PJM RTO for the summer of 2009 is 127,400 MW. For the summer of 2018, NID is projected to be 149,800 MW. The compound annualized growth rate (CAGR) of the NID forecast is 1.8 percent from 2009 to 2018. This is higher than the 1.6 percent CAGR of last year's NID forecast. These values are based on the Total Internal Demand (TID) demand forecast prepared by PJM staff with the full utilization of the Demand Response programs approved for use in the PJM Reliability Pricing Model (RPM). The forecast is dated January 2009, and is based on economic data from late 2008.

The impact of various Demand Response programs are included in the load forecast if approved for use in the PJM RPM. At time of the 2009 load forecast publication, no Energy Efficiency programs have been approved as an RPM resource. At time of the 2009 load forecast publication, PJM's measurement and verification protocols were under development for Energy Efficiency programs.

Direct Control Load Management and Interruptible Demand are programs approved for use in RPM. Direct control amounts to 700 MW with an additional 6,300 MW of Interruptible Demand. The analysis assumes the Demand Response remains constant in PJM throughout the assessment period.

The estimated Total Internal Demand (TID) of PJM RTO for the 2009 summer season is 134,400 MW and is forecast to increase to 156,800 MW by 2018. The CAGR of the 2009 TID forecast is 1.7 percent, which is slightly higher than the 1.6 percent CAGR last year for 2008 to 2017.

MIDWEST ISO Demand Data

The estimated Net Internal Demand peak of the entire Midwest ISO Market for the summer of 2009 is projected to be 100,100 MW. For the summer of 2018, NID is projected to be 109,400 MW. The compound annualized growth rate (CAGR) of the NID forecast is 1.0 percent from 2009 to 2018. This is lower than the 1.5 percent CAGR of last year's NID forecast. These values are based on the Total Internal Demand (TID) forecast developed by the MISO market participants with the full utilization of Demand Response programs. These demand forecasts have been developed at different times throughout the last half of 2008 and early 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 available for the summer of 2009 is 2,400 MW. This is categorized as 600 MW of Load Management with an additional 1,800 MW of Interruptible Demand. The analysis assumes the Demand Response remains constant in MISO throughout the assessment period.

The estimated TID of MISO for the 2009 summer season is 102,500 MW and is forecast to increase to 111,800 MW by 2018. The CAGR of the 2009 TID forecast is 1.0 percent, which is lower than the 1.5 percent CAGR last year for 2008 to 2017.

RFC Demand Data

The Region is expected to be summer peaking throughout the study period, therefore this assessment will focus its analysis on the summer demand period. In this assessment, the data related to the Reliability*First* areas of PJM and MISO is 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 estimated coincident Net Internal Demand (NID) peak of the entire RFC Region for the summer of 2009 is projected to be 169,900 MW. For the summer of 2018, NID is projected to be 193,100 MW. The compound annualized growth rate (CAGR) of the NID forecast is 1.4 percent from 2009 to 2018. This is slightly lower than the 1.5 percent CAGR of last year's NID forecast.

The Demand Response reported by PJM and MISO in 2009 amounts to 1,300 MW of Direct Control Load Management with an additional 6,900 MW of Interruptible Demand. The analysis assumes the Demand Response remains constant throughout the assessment period in PJM and MISO.

The TID for the summer of 2009 is projected to be 178,100 MW. For the summer of 2018, TID is projected to be 201,300 MW. The compound annualized growth rate (CAGR) of the TID forecast is 1.4 percent from 2009 to 2018. This is the same as last year's TID forecast.

Recent economic conditions have significantly reduced (by 4.8 percent) the forecast peak demand for 2009 (178,100 MW TID) over the 2008 forecast for 2009 (187,100 MW TID). The projected growth rate varies throughout the individual load zones within PJM and the Local Balancing Authorities within MISO from no expected load growth to greater than 4 percent annual growth over the ten-year assessment period.

Generation

The Existing Capacity in this assessment represents the capability of the generation in OVEC and in all of the PJM and MISO market areas.

The Other Existing Capacity resources are the existing generation resources within the RTOs or Region that is not included in the Reserve Margin calculations. Included in this category would be the derated portion of wind/variable resources, generating capacity that has not been studied for delivery within the RTO, and capacity located within the RTO that is not part of PJM committed capacity or MISO Capacity Resources. Also, units scheduled for maintenance and any existing generators that are inoperable are excluded from the Existing, Certain Capacity category when determining Reserve Margins.

The capacity represented by the Existing Capacity less the Other Existing Capacity is the category of Existing, Certain Capacity, which is comprised of the existing resources in PJM's Reliability Pricing Model (RPM) and the capacity resources in the MISO market.

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 capability is assigned for each missing year of data for that project. In MISO, wind power providers may declare as a capacity resource, up to 20 percent of the nameplate capability. The difference between the nameplate rating and the expected wind capability is accounted for in the Other Existing category.

PJM Generation

The entire PJM RTO has 166,200 MW of Existing, Certain and Future, Planned capacity for 2009. There is also 1,800 MW of Other Existing Capacity for the entire ten-year assessment period. The net increase in capacity through 2018 is 3,800 MW, based on Future Planned Capacity and the retirement of existing generation. The amount of conceptual capability in this assessment included by PJM from the generator interconnection queue is 43,100 MW. The confidence factor provided by PJM and used by Reliability*First* to calculate the amount of conceptual capacity to be included in the assessment of future reserve margins is 18.4 percent (8,000 MW).

MISO Generation

The Midwest ISO market has 117,400 MW of Existing, Certain capacity for the 2009 summer. There is also 12,300 MW of Other Existing Capacity that is not included as a firm capacity resource for the entire ten year assessment period. The increase in Future Planned Capacity through 2018 is 400 MW. Conceptual Capacity of 21,600 MW from the MISO generator interconnection queue projects in the RFC Region is included by MISO in this assessment. Based on the confidence factor provided by MISO, RFC has included 19.1 percent (4,100 MW) of the conceptual capacity to calculate the expected future reserve margins.

RFC Generation

The RFC data only includes generation physically located within the Reliability*First* Region, although generating capacity outside the Regional area owned by member companies may be included with the scheduled power imports.

The amount of OVEC, PJM, and MISO existing and planned generating unit capacity in RFC is 215,600 MW. There is also 4,500 MW of Other Existing capacity in the ten-year assessment period, which is not included in the reserve margins analysis. The net increase due to Future Capacity Additions and retirements through 2018 is 4,000 MW. There are also 8,500 MW of Conceptual Capacity, which are included in the reserve calculations. This represents 46,400 MW of Conceptual Capacity with an 18.4 percent confidence factor. When the net import of 200 MW at the time of the peak is included, total expected capacity resources are 228,300 MW in 2018, which is a 18.4 percent reserve margin.

Within Reliability*First* there is about 1,600 MW of existing nameplate wind turbine capacity, with 300 MW being included as on-peak capacity for reserve requirements. There is also approximately 7,000 MW of additional existing renewable resources, including pumped hydro, within the Region. About 700 MW of biomass is included in the renewable totals.

Capacity Transactions on Peak

PJM and MISO have reported Capacity Transactions (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 non-curtailable transactions with firm transmission reservations, identified by PJM and MISO as interchange that supports their Reserve Margins, are the only transactions included in the assessment of Reserve Margins.

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 Reliability*First*, the jointly-owned and OVEC generation is included in Reliability*First*'s generation and not the Reliability*First* net interchange. Additional transfers between the RTOs that originate and terminate within the Reliability*First* Region will also not be included in the Reliability*First* interchange. Therefore, the total net interchange for the Reliability*First* Region is not a simple summation of the PJM and MISO RTO interchange.

PJM Net Interchange

Firm power imports into PJM are reported to be 3,700 MW in 2009 decreasing to 3,000 MW in 2018. Firm power exports are reported to be 2,400 MW in 2009 increasing to 2,800 MW by 2018. Net interchange is a 1,300 MW power import flowing into the PJM RTO in 2009 decreasing to a 200 MW import by 2018.

MISO Net Interchange

MISO only has information on firm power imports, which are 4,300 MW committed to the MISO market in 2009. This amount of net import is assumed for the entire assessment period.

Information on exported power is not available since this power is supplied from resources that are not committed to the MISO market.

RFC Net Interchange

The Capacity Transactions in OVEC, MISO and PJM at the time of the peak that cross the Reliability*First* Regional boundary are projected to be 1,300 MW of imports into the Reliability*First* Region and 1,100 MW of exports, for a net import of 200 MW. These include only firm transactions. Other transactions, which may occur, are not considered firm transactions and are not included in this assessment. Forecasts of future interchange transactions are very speculative, since they rely on generation resources that are in other Regions. While Reliability*First* believes significant power could be imported into the Region when necessary, only this 200 MW of net import has been included in determining the future Reserve Margins.

Transmission

Plans within Reliability*First* for the next seven years include the addition of over 1,700 miles of high voltage transmission lines that will operate at 100 kV and above, as well as numerous new substations and transformers that are expected to enhance and strengthen the bulk transmission system. Most of the new additions are connections to new generators or substations. MISO has identified many new projects as part of the Midwest ISO Expansion Plan (MTEP). Individual MISO projects referenced at http://www.midwestmarket.org/page/Expansion%20Planning.

Furthermore, there are several "backbone" transmission projects that are planned within Reliability*First*. PJM's Regional Transmission Expansion Plan (RTEP) has identified four major "backbone" projects, one from the 2006 RTEP and three additional ones from the PJM Board-approved 2007 RTEP. Additional PJM RTEP project information can be referenced at http://www.pjm.com/documents/reports/rtep-report.aspx.

The Trans-Allegheny Interstate Line (TrAIL) project (see http://www.aptrailinfo.com) from the 2006 RTEP is a new 210-mile, 500 kV RFC-SERC interconnection and is scheduled for operation in 2011. This project consists of a new 500 kV circuit from 502 Junction to Mt. Storm to Meadow Brook to Loudon. This project will relieve anticipated overloads and voltage problems in the Washington, D.C. area, including overloads expected in 2011 on the existing 500 kV network. The period before the existing facilities become overloaded presents a very challenging timeframe for the development, licensing, and construction of this project.

The three other PJM "backbone" projects from the 2007 RTEP are planned. One is the 130-mile, 500 kV circuit from Susquehanna to Lackawanna to Roseland that will tie into the existing 500 kV network where multiple 230 and 115 kV circuits are tightly networked. This circuit then will continue to Roseland. Also, 500/230 kV transformers are proposed at Lackawana and Roseland substations. This circuit and the transformer additions will create a strong link from generation sources in northeastern and north-central Pennsylvania into New Jersey. These facilities are expected to be in-service by June 2012.

The Potomac-Appalachian Transmission Highline (PATH) (see http://www.pathtransmission.com/overview/default.asp) is the second "backbone" project, and consists of a 244-mile Amos to Bedington 765 kV line and a 92-mile, twin-circuit 500 kV line from Bedington to Kemptown. This project will bring a strong source into the Kemptown, Maryland area by reducing the west-to-east power flow on the existing PJM 500 kV transmission paths and provide significant benefits to the constrained area of Washington, D.C. and Baltimore. These facilities are expected to be in-service in 2012.

The third "backbone" project is the Mid-Atlantic Power Pathway (MAPP), which consists of a new 190-mile 500 kV line beginning at Possum Point, Virginia and terminating at Salem, New Jersey. See http://www.powerpathway.com/overview.html for more information.

Currently, the only approved major project within the RFC area of the Midwest ISO is the Vectren 345 kV line from Gibson (Duke) – AB Brown (Vectren) – Reid (BREC). This line is expected to be in-service in 2011.

Phase Angle Regulators (PARs) on all major ties between northeastern PJM and southeastern New York help control unscheduled power flows through PJM resulting from non-PJM power transfers.

Phase angle regulators are currently installed on three of the four Michigan to Ontario interconnections. One phase angle regulator, on the Keith to Waterman 230 kV circuit J5D has been in service and regulating since 1975.

The other two available phase angle regulators, on circuits L51D and L4D, are currently bypassed during normal operations, but are available for use during emergency operations. They will become operational once agreements between the IESO, the Midwest ISO, Hydro One, and the International Transmission Company, are finalized. The operation of the phase angle regulators will assist in the control of circulating flows. The fourth phase angle regulator(s) (2 phase angle regulators in parallel), which is responsible for controlling the tie flow on the 230 kV circuit B3N, is scheduled for replacement in 2010 (However, replacement could be complete by the end of 2009.). The replacement phase angle regulators will be located in Michigan at the Bunce Creek terminal of the B3N circuit.

Historically, Reliability*First* (including the heritage Regions) has 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 re-dispatch has the potential to mitigate these potential constraints. Notwithstanding the benefits of this re-dispatch, should transmission constraint conditions occur, local operating procedures as well as the NERC transmission loading relief (TLR) procedure may be required to maintain adequate transmission system reliability.

The transmission system 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. Both MISO and PJM perform comprehensive generator and load deliverability studies, which ensures the transmission system is capable of delivering the generation in their respective markets to satisfy system demand.

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 or procedures with minimal reliability impact. There are a number of new capacitors expected to be placed in-service across the PJM system in the summer of 2009 that will increase reactive capability by more than 1,900 Mvar. Reliability*First* does not anticipate any significant impact on reliability from scheduled generating unit or transmission facility outages.

No unit outages, variable resources, or transmission additions are anticipated to impact reliability for this assessment period. However, some transmission system upgrades may cause operational challenges, but scheduled outages will not be taken unless reliability can be maintained. Special operating procedures are expected to mitigate any of these challenges. Unit outages are only evaluated seasonally and not on a long-term basis, except for the maintenance of nuclear units.

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

Variability of forecasted demand is accounted for in the determination of the PJM required Reserve Margin. The PJM forecast uses a Monte Carlo process that produces forecasts over all weather experienced over the last 35 years. The resulting 455 scenarios are rank ordered, with the median value being the base forecast. This extensive distribution of forecasts allows for estimation of peak load uncertainty at all probability levels of weather. When necessary, PJM implements emergency procedures identified in the PJM Emergency Procedures Manual (M13), Section 2: Capacity Conditions.

Under extreme hot weather conditions, some units on Lake Michigan may have restricted output if water the 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 limit the discharge of cooling water into the Wabash and White Rivers in order to maintain the downstream water temperature within limits. 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 of power curtailments to maintain downstream temperature limits 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 operational reliability assessments and neither anticipates any unique operational concerns with traditional or distributed generation.

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. There are no announced generator retirements in the MISO capacity plans.

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 use for electric generation.

Reliability*First* is dependent on natural gas as a fuel for the peak demand, particularly in the summer. More than 25 percent of the Regional capacity is fueled by gas. Although natural gas use for electric generation in the summer has increased significantly in recent years, the peak use of gas for all purposes is during the winter season. Reliability*First* does not expect any problem with gas availability to affect the long term assessment.

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.

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 the long-term assessment.

Reliability*First* members are ready to mitigate any fuel supply disruption that may occur. Some members may resort to fuel switching for those units with dual-fuel capability, if it becomes necessary to maintain reliable fuel supplies. Data available to Reliability*First* indicates that 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. Reliability*First* does not anticipate the need for any fuel switching in order to maintain reliable fuel supplies for the long-term assessment.

Since there currently are no adverse conditions affecting the resources within the RFC Region, this assessment assumes that any future adverse weather or fuel supply issues would be temporary in duration and limited in impact on resource availability, and will not affect the results of the Reserve Margin calculation. No other unusual operating conditions that could impact reliability are foreseen for this assessment period.

Reliability Assessment Analysis
Analyses were conducted by the Midwest Loss of Load Expectation (LOLE) Working Group and PJM at the end of 2008 or early 2009 to satisfy the Reliability*First* requirement for Planning Coordinators to determine the Reserve Margin at which the LOLE is one-day-in-ten years (0.1 day/year) on an annual basis for their planning area. These analyses include demand forecast uncertainty, outage schedules, the determination of transmission transfer capability, internal deliverability, CBM, and other external emergency sources, treatment of operating reserves, and

other relevant factors when determining the probability of firm demand exceeding the available generating capacity. The assessment of PJM resource adequacy is based on reserve requirements determined from its analysis. The PJM Reserve Margin requirement for 2009 to 2010 is 15.0 percent, for 2010 to 2012 is 15.5 percent and projected to be 16.2 percent thereafter. Similarly, the assessment of MISO resource adequacy is based on reserve requirements determined from its analysis. The Midwest ISO's Reserve Margin target for 2009 is 15.4 percent, and is used to assess each of the 10 years in this analysis.

Reliability*First*'s Resource Assessment Subcommittee believes it is reasonable to assess the overall resource adequacy of the Reliability*First* Regional area by assessing the resource adequacy of the RTOs that operate within the Regional area. This is possible since the determination of each of the RTO Reserve Margin targets has been performed in a manner consistent with the requirements contained in BAL-502-RFC-002. The Resource Assessment Subcommittee believes that when Reliability*First* has assessed each RTO to have sufficient resources to satisfy their respective Reserve Margin requirement, then the Reliability*First* area of each RTO also has sufficient resources. Therefore, when each RTO area of Reliability*First* has sufficient resources, the Reliability*First* Regional resources can be assessed as adequate.

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 Eastern Interconnection Reliability Assessment Group indicate there is more than 4,000 MW of transfer capability between the RTOs. The limited use of transfer capability in the reserve requirement studies provides a level of conservatism in this assessment.

It is important to note the capacity resources identified as Existing Certain in this assessment have been pre-certified by either PJM or MISO as able to be utilized within their RTO market area for the first year of the assessment period. This means that these resources are considered to be fully deliverable within and recallable by their respective markets. Both PJM and MISO include in the Existing, Certain category only those generator resources determined to satisfy their respective deliverability requirements. In both RTOs there are additional resources identified as Other Existing that may be available to serve load.

Reliability*First* has not performed any sensitivity analyses for high resource unavailability or high demand due to weather conditions. Any condition that increases Regional demand or generation resource unavailability beyond the forecast conditions in the assessment analysis will decrease overall resource reliability. However, over the ten-year assessment period, extreme weather, fuel interruptions, and droughts are considered to be short-term conditions that are not included when determining long-term reliability targets. Over time, any adverse trends in forced outage rates will be factored into the analyses required by the Reliability*First* Planned Resource Adequacy Standard, and the Reserve Margin targets will reflect the need for higher reserves. A number of operating plans and procedures, including generator redispatch, would be expected to be deployed to mitigate adverse conditions during this assessment period.

PJM Reserve Margins

The reserve margin calculations include Existing, Certain capacity, Future, Planned capacity, the projected amount of Conceptual capacity determined from the confidence factor, and the net capacity transactions. For 2009, this is 167,800 MW of Net Capacity Resources, which provides 40,400 MW of reserves. This is a 31.7 percent reserve margin based on NID. Given PJM's projected changes in reserve margin targets, the reserve margins are expected to meet its reserve margin target of 16.2 percent through 2018.

MISO Reserve Margins

The reserve margin calculation includes Existing, Certain capacity, Future, Planned capacity, the projected amount of Conceptual capacity determined from the confidence factor, and the net capacity transactions. For 2009, this is 121,800 MW of Net Capacity Resources, which provides 21,600 MW of reserves. This is a 21.6 percent reserve margin based on NID. The reserve margins in MISO are expected to meet its reserve margin target through 2018.

RFC Reserve Margins

The reserve margin calculation includes Existing, Certain capacity, Future, Planned capacity, the projected amount of Conceptual capacity determined from the confidence factor, and the net capacity transactions. For 2009, this is 216,100 MW of Net Capacity Resources, which provides 46,200 MW of reserves, or a 27.2 percent reserve margin based on NID.

Reliability*First* bases its assessment of the Regional area on the combined assessments of the PJM and MISO RTOs. Each RTO is expected to have sufficient resources based on Existing, Planned, and Conceptual Resources through 2018. Therefore, RFC expects the Regional area to have adequate reserve margins throughout the entire assessment period.

Both MISO and PJM conduct comprehensive detailed generator load deliverability studies. MISO deliverability test results can be found at http://www.midwestmarket.org/page/Generator+Interconnection+Support+Documents under Generator Deliverability Tests. For more information on PJM deliverability, see Appendix E of the PJM Manual 14b at http://www.pjm.com/documents/~/media/documents/manuals/m14b.ashx. Results of the PJM analysis are evaluated continuously as part of the normal PJM planning process and presented as part of the Transmission Expansion Advisory Committee (TEAC) meetings. See http://www.pjm.com/committees-and-groups/committees/teac.aspx for more details. Neither MISO nor PJM have any deliverability concerns for this assessment period.

Although demand is projected to increase each year of the assessment period, due to the economic recession, the current demand forecast for 2009 starts at a level significantly below the level expected for 2009 in last year’s forecast.

Transmission-limited and energy-only units are not considered in reliability analysis. They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance.

Renewable Energy

Many states in the RFC Region have Renewable Portfolio Standards (RPS). It is up to the individual 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 its 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.

RPS's 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 MISO policy changes.

PJM performs voltage stability analysis (including voltage drop) as part of all planning studies and also as part of a periodic (every five minutes) analysis performed by the energy management system (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. MISO also performs transient stability analysis.

The Cleveland area was shown to be a reactive power-constrained area from the 2003 blackout. However, actions have been taken to mitigate future reactive resource problems associated with this area. These include the installation of capacitor banks and an automatic under voltage load shed (UVLS) scheme (as mentioned below) and enhanced monitoring of dynamic reactive resources and system conditions in that area. FirstEnergy has reactive reserve criteria for this area.

There are currently three automatic 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. 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.

Reliability*First* does not specifically study catastrophic events and is not aware of any specific studies. However, registered entities such as Transmission Planners may conduct their own extreme analyses.

Reliability*First* staff plus MISO, PJM, and the transmission planners within RFC all perform studies to analyze future transmission system configurations in accordance with the requirements in the NERC TPL standards. Results of the RFC studies are summarized in the RFC seasonal, near-term, and long-term transmission assessment reports. These reports are posted at http://www.rfirst.org/Reliability/ReliabilityHome.aspx.

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.

New technologies and tools are being utilized within Reliability*First* to improve bulk power system reliability. Several companies plan or are in the process of installing High Temperature Low Sag (HTLS) conductors while others are aggressively investing in Smart Grid technology. PJM is developing a Wind Power Forecast Tool and increased visualization within Dispatch. Other new technologies include Transient Stability Analyzer, Generator Performance Monitor, providing PJM Security Analysis results in the Transmission Operator control rooms, and the development of a new back-up control center. PJM began utilizing a centralized Wind Power Forecast within operations on 4/1/2009. PJM is actively integrating the Wind Power Forecast within PJM market/operational manuals, procedures and toolsets.

Reliability*First* does not maintain a Regional short-circuit database, which would be required to accurately assess the short-circuit levels within RFC. As a result, RFC does not conduct a specific assessment of short-circuit levels, does not have a mechanism to assist RFC members in maintaining short-circuit equivalents outside their own system, and does not have a strategy to address short-circuit levels with respect to either installed equipment capabilities or the limits of existing technology. Each Transmission Owner and Planner obtains suitable short-circuit equivalents from neighboring Transmission Owners to assess their own system and to develop and implement any necessary mitigation strategies. In addition, short circuit analysis is performed as part of the PJM RTEP analysis.

No significant trends within Reliability*First* have been noted that would suggest that aging infrastructure is becoming an issue.

Reliability*First* does not have any guidelines to share inventory of spare equipment. However, many member companies maintain an inventory of spare generator step-up (GSU) and auto transformers following their own internal criteria.

Even with the current economic recession, 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 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 long-term assessment.

Region Description

*Reliability*First *currently consists of 47 Regular Members, 22 Associate Members, and four Adjunct Members operating within three 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

Introduction

The SERC Reliability Corporation (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 68 million or 22 percent of the U.S. population. Most electric utilities within the SERC Region 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 services to customers over a broader area through congestion-based location marginal pricing. Companies within SERC are closely interconnected and the Region has operated with high reliability for many years.

It should be noted the generation capacity figures provided here are based on the data submitted to also fulfill utility reporting requirements under the 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 generation is not determinable but it is estimated that there is approximately 1,875 MW of generation in the SERC Region that is in addition to what is reported in the EIA 411 report. This is a significant improvement in reporting over the 2008 report, which showed 28,000 MW of such generation. The key reason for this improvement is that in 2009 SERC staff reached out to all registered Generator Owners and Generator Operators to collect data at the generating unit level. SERC continually educates entities that all existing "iron in the ground" capacity be reported in one category or another as specified by the NERC instructions. In addition, resources and reserve margins provided here are based on firm arrangements put in place in early 2009.

Capacity resources in the Region as a whole are expected to be adequate to reliably supply the forecast firm peak demand and energy needs throughout the long-term assessment period. Reported potential capacity additions and existing capacity, including uncommitted resources, along with the necessary transmission system upgrades, are projected to satisfy reliability needs through 2018. The outcomes in terms of resource adequacy is highly dependent on regulatory support for generation expansion plans, new state, local, and federal environmental regulations impacting operation of existing generating resources; state and local environmental and citing process regulations that influence the development of new generating resources.

SERC members have extensive transmission interconnections with neighboring regions (FRCC, MRO, RFC, and SPP). These interconnections allow the exchange of firm and non-firm power and allow systems to assist one another in the event of an emergency.

Transmission capacity is expected to be adequate to supply firm customer demand and firm transmission reservations. Like capacity and resource adequacy, the outcomes in terms of adequacy of transmission capacity are dependent on regulatory support for transmission expansion plans.

SERC members invested approximately $1.5 billion in transmission system upgrades to 100 kV and above in 2008, plan to invest approximately $1.7 billion in 2009, and are planning transmission capital expenditures of more than $8.8 billion over the next five years. Planned transmission additions over the next 10 years include 212 miles of 100–120 kV lines, 95 miles of 151–199 kV lines, 748 miles of 230–299 kV lines, 114 miles of 300–399 kV lines, and 302 miles of 400–599 kV lines. Conceptual transmission additions over the next ten years include 338 miles of 100–120 kV lines, 40 miles of 121–150 kV lines, 43 miles of 151–199 kV lines, 1,123 miles of 200–299 kV lines, 242 miles of 300–399 kV lines, and 295 miles of 400–599 kV lines. The transmission lines under construction at the time of this assessment include 91 miles of 100–120 kV lines, 60 miles of 121–150 kV lines, 90 miles of 151–199 kV lines and 279 miles of 200–299 kV lines, 230 miles of 300–399 kV lines, and 35 miles of 400–599 kV lines.

Within the SERC Region footprint there are utilities that are part of the PJM RTO, which implement and manage a capacity market. MISO operates a centralized energy market, which involves some utilities within SERC. The other utilities within SERC are traditional and vertically-integrated and do not participate in centralized RTO-based markets.

Demand

SERC is a summer-peaking Region. The total internal demand with SERC for the 2009 summer is forecast to be 201,368 MW, which is 7,740 MW (3.7 percent) lower than the all-time peak of 209,108 MW that occurred in August 2007 and is 1,952 MW (1 percent) lower than the forecast 2008 summer peak of 203,320 MW. The 2009 summer net internal demand forecast is 195,501 MW and the forecast for 2018 is 228,862 MW. The average annual growth rate over the next 10 years is 1.8 percent. This is lower than last year's forecast growth rate of 1.9 percent. The historical growth rate of actual peaks has averaged 1.6 percent over the last nine years. With load generally down as compared to the prior year, the system has been tested at greater load levels in prior periods.

All reported demands are non-coincident. These projections are based on average historical summer weather and are the sum of non-coincident forecast data reported by utilities in the SERC Region. Some entities have lowered their forecasts as compared to previous period forecasts due to the current economic recession. There were no significant changes in weather assumptions but the economic recession is causing a near-term drop in demand. Rebound in the long-term is expected. Temperatures that are higher or lower than normal and the degree to which interruptible demand and Demand Side Management (DSM) is utilized can result in actual peak demands that vary considerably from the reported forecast peak demand

While member methodologies vary to account for differences in system characteristics, the methodologies share many common considerations including:

- 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

In addition, many SERC members use sophisticated, industry-accepted methodologies to evaluate load sensitivities in the development of load forecasts.

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.

Members of the SERC Region have significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. The amount of interruptible demand and load management is expected to increase slightly over the forecast period from 5,867 MW in 2009 to 8,525 MW in 2018. Amounts for 2009 are lower than last year's projections due to the change in reporting philosophy regarding demand response programs within certain companies. Traditional load management and interruptible programs such as air conditioning load control and large industrial interruptible services are common within the Region. 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

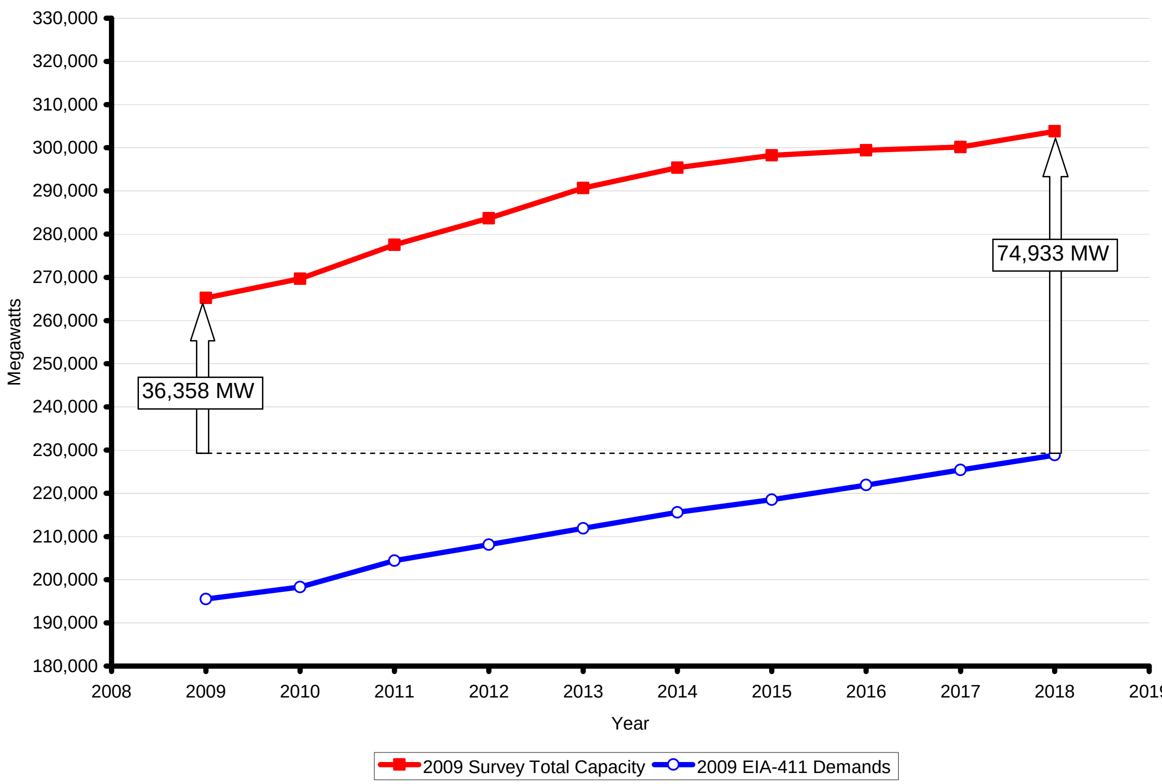
Program	2008 Summer	2009 Summer	Summer 2018
Direct Control Load Management	970 MW	972.1 MW	3,023 MW
Contractually Interruptible (Curtailable)	4,953 MW	4,624 MW	5,200 MW
Critical Peak-Pricing (CPP) with Control	221 MW	0 MW	41 MW
Load as a Capacity Resource	125 MW	271 MW	260 MW
Energy Efficiency Programs	81 MW	1,294 MW	1,314 MW

Ambient temperatures that are higher or lower than normal and the degree to which interruptible demand and DSM is utilized, result in actual peak demands that vary from the forecast. Utilities within SERC perform detailed extreme weather and load sensitivity analyses in their respective operational and planning studies.

Generation

Reported potential capacity additions and existing capacity along with the necessary transmission system upgrades is expected to satisfy reliability needs through 2018. As can be seen in SERC Figure 1, the range of outcomes is quite wide, particularly for the out years. The outcomes in terms of resource adequacy are highly dependent on regulatory support for generation expansion plans, new state, local, and federal environmental regulations impacting operation of existing generating resources; state and local environmental and citing process regulations that influence the development of new generating resources.

SERC Figure 1: Potential Generation Plant Development in SERC



Specifically, utilities within the SERC Region expect to have 259,169 MW of resources including 243,296 MW of Existing, Certain resources and 14,348 MW of Existing, Other resources in 2009. This does not include 2,464 MW of inoperable resources for this upcoming summer. The utilities in the SERC Region anticipate 1,221 MW of Future, Planned and Future, Other as well as 304 MW of Conceptual capacity resources during the 2009 period. By 2018 the utilities within the SERC Region expect to have 287,325 MW of resources including 235,238 MW of Existing, Certain resources, and 17,106 MW of Existing, Other resources. This does not take into account 4,740 MW of inoperable units. Utilities within the SERC Region expect future capacity additions by 2018 of 23,022 MW including the Future, Planned and the Future, Other category, as well as 11,599 MW of Conceptual capacity resources.

SERC has improved the reporting of generation and transactions. SERC member responses to the annual SERC Reliability Review Subcommittee's (RRS) Generation Plant Development Survey indicate 4,200 MW resource difference between the Survey and the LTRA reporting. This is substantially improved from prior years differences between these two approaches. We will be working to resolve this difference further in future years.

The projected 2009 capacity mix reported for SERC members is approximately 37.8 percent coal, 14.5 percent nuclear, 8.5 percent hydro/pumped storage, 38.8 percent gas or oil, and 0.4 percent for purchases and miscellaneous other capacity. The mix has not changed significantly from last year nor will the mix be appreciably different by 2018. Generation with coal and nuclear fuels continues to lead the Region's fuel mix, accounting for roughly 52.3 percent of net operable capacity in 2009.

The majority of planned capacity additions, as reported by member systems in the EIA-411 filings, is comprised of nuclear, gas/oil fueled combustion turbine, or combined cycle units. However, there are recent announced additions and plans in the 10-year planning horizon for coal-fired plant additions.

Resources are expected to be adequate even if resource unavailability is higher than expected since utilities in the SERC Region recognize that planning for variability in resource availability is necessary. Many utilities in the SERC Region manage this variability through reserve margins, DSM programs, fuel inventories, diversified fuel mix and sources, and transfer capabilities. Some SERC members participate in Reserve Sharing Groups (RSG). In addition, emergency energy contracts are used within the Region and with neighboring systems to enhance recovery from unplanned outages.

Generation facilities are planned and constructed to ensure that aggregate generation capacity keeps pace with 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 systems and selling their output into the electricity market where such markets exist within the SERC Region.

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 2009 period were reported to total 873 MW with 279 MW reported as uncommitted. The uncommitted generation includes 100 MW of wind (80 MW is energy only) and 179 MW of natural gas where all 179 MW is energy only. For the 2009 to 2018 period the total net projected additions are 39,449 MW comprised of 25,099 MW of interconnection service requested, 15,961 MW of interconnection agreements signed or filed, and 1,611 MW of retirements. Of the total net projected additions, 14,248 MW are detailed as uncommitted generation. 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[168] generation in the SERC Region totaling 214 MW.

Some examples of major generating plant developments proposed by utilities in the SERC Region are:

Potential Additions:

- Central Subregion: 750 MW coal addition in 2010; 1,185 MW nuclear in 2012
- Delta Subregion: no major additions

[168] Defined by EIA as: *"organic non-fossil material of biological origin constituting a renewable energy source"*

- Gateway Subregion: 200 MW coal addition in 2009; 1,650 MW merchant coal plant in 2011-2012; 1,650 MW nuclear addition in 2018
- Southeastern Subregion: 1,680 MW combined cycles in 2011; 840 MW combined cycles in 2012; 1,100 MW nuclear addition in 2016; 1,100 MW nuclear addition in 2017
- VACAR Subregion: 825 MW coal addition in 2012; 605 MW coal addition in 2014; 1,100 MW nuclear addition in 2016

Of the approximately 18,364 MW of planned resource additions reported for the 2009 to 2018 time period, 25.9 percent are combined cycle, 3.9 percent are combustion turbine, 33.1 percent are steam (including nuclear), 28 percent are net purchases, 6.5 percent are hydro, 2.7 percent are pumped storage and -0.1 percent are categorized as “Other/Unknown”. The “Other/Unknown” category includes potential additions that do not have finalized implementation plans. It appears that entities are continuing to increase plans for future coal or nuclear-base load generation instead of relying on natural gas-fired generation or purchases. However, in the Central sub-Region the Environmental Policy of one entity anticipates increasing its proportion of generation from non-carbon sources from 30 percent to 50 percent by 2020.

Capacity Transactions on Peak

Firm sales that cross the SERC Regional boundary total 8,737 MW in 2008 and firm purchases that cross the boundary total 8,801 MW in 2009. These firm sales and purchases have been accounted for in the reserve margin calculations for the Region. Overall, the utilities within the Region are not considered to be dependent on purchases or transfers outside SERC to meet the demands of the load within SERC.

Table SERC - 2: Purchases and Sales MW

Transaction Type	Summer 2009	Summer 2013	Summer 2018
Firm Imports	8, 801 MW	9,180 MW	11,373 MW
Firm Exports	8,737 MW	5,105 MW	4,167 MW
Non-firm Imports	0 MW	0 MW	0 MW
Non-firm Exports	172 MW	172 MW	172 MW
Expected Imports	0 MW	0 MW	0 MW
Expected Exports	0 MW	0 MW	0 MW
Provisional Imports	0 MW	100 MW	75 MW
Provisional Exports	0 MW	0 MW	0 MW

Transmission

The existing bulk transmission systems within SERC total 97,256 miles of transmission lines comprised of 37,471 miles of 100–121 kV, 9,103 miles of 121–150 kV, 18,040 miles of 151–199 kV, 20,710 miles of 200–299 kV, 3,297 miles of 300–399 kV, and 8,635 miles of 400–599 kV transmission lines. SERC member systems continue to plan for a reliable bulk transmission system and plan to add 643 miles of 100–120 kV, 415 miles of 151–199 kV, 2,169 miles of 300–399 kV, 587 miles of 300–399 kV, and 667 miles of 400–599 kV transmission lines in the 2009 to 2018 time period. As reported in the *2008 NERC Long-Term Reliability Assessment Report*, the bulk transmission expansion plans of the SERC Region utilities are second only to WECC. Furthermore, the planned transmission expansion in SERC represents approximately 20 percent of all transmission expansion in the U.S. over the next 10 years. This marks the seventh consecutive year in which SERC has reported at least one–fifth of all planned U.S. transmission expansion.

SERC Region utilities spent approximately $1.5 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. Investments over the 2009 to 2013 period total $8.8 billion dollars; $1.7 billion in 2009, $1.9 billion in 2010, $1.6 billion in 2011, $1.8 billion in 2012, and $1.8 billion in 2013.

SERC member transmission systems are directly interconnected with the transmission systems in FRCC, MRO, RFC, and SPP. Transmission studies are coordinated through joint interregional reliability study groups. The results of individual system, Regional and interregional studies help to demonstrate that the SERC member transmission systems meet NERC Reliability Standards.

Results from the Eastern Interconnection Reliability Assessment Group (ERAG) sponsored 2009 Summer MRO-RFC-SERC West-SPP Inter-Regional Transmission System Assessment indicate potential transmission transfer issues between the Delta subregion and some neighboring Regions involved in the study. The areas of interest from this study indicate the First Contingency Incremental Transfer Capability (FCITC) from the Delta subregion to neighboring interfaces SPP and MRO is “zero”. Details of planned upgrades to address this potential constraint are provided in the Delta subregion portion of this report. These transfers are primarily limited by 161 kV transmission facilities on the Entergy-SPP interface for the outage of a tie line between Entergy and Oklahoma Gas & Electric.

In addition, the following transmission facility upgrades are scheduled for completion by the 2011 winter operating season to mitigate potential loading on certain transmission facilities that are located on the interface between Entergy and neighboring SPP systems:

- ANO – Russellville North 161 kV line (upgrade to at least 450 MVA)
- Russellville East – Russellville South 161 kV line (upgrade to at least 370 MVA)
- Bismarck – Hot Springs 115 kV line (upgrade to at least 120 MVA)
- Bismarck – Alpine – Amity 115 kV line (upgrade to at least 120 MVA)

The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demand and energy requirements and firm transmission service commitments during normal and applicable contingency system conditions as prescribed in the NERC Reliability Standards (see Table 1, Category B of NERC Reliability Standard TPL-002-0) and the member companies’ planning criteria relating to transmission system performance. 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.

Coordinated interregional transmission reliability and transfer capability studies for the 2009 to 2018 period are conducted among all utilities in the SERC subregions and with neighboring Regions. Results of these studies indicate the bulk transmission systems within the SERC Region have no issues that will significantly impact reliability. One potential limit in the near-term horizon is a constraint on the Delta-SPP interface. As discussed above, upgrades are being constructed or are underway.

Details of the transmission line and transformer additions are discussed in the subregion reports including tables showing significant transmission projects.

Operational Issues (Known or Emerging)
No major generator outages are planned for the period that could impact bulk power system reliability.

Environmental restrictions are not expected to significantly impact operations in the SERC Region in the near term 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 ended.

Operational planning studies are discussed in detail in the subregion reports of the SERC report.

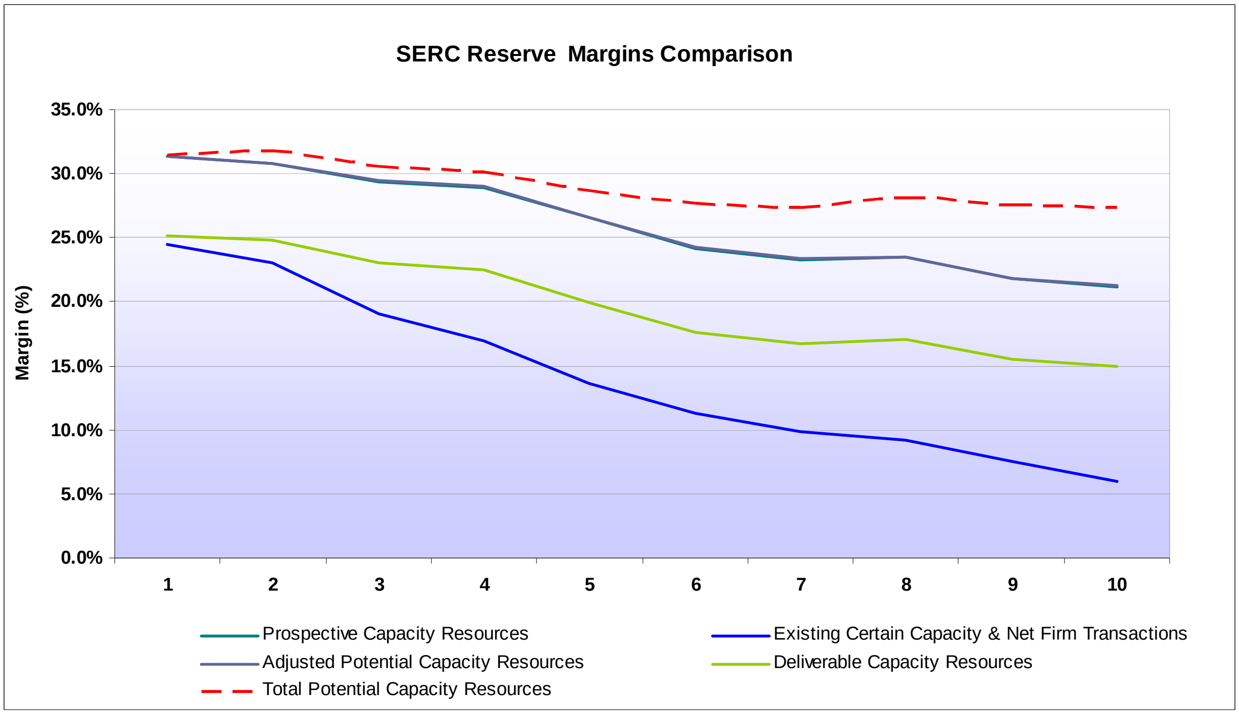
In general, there are no operational changes required of utilities in the SERC Region to implement the integration of variable generation such as wind and solar. Most of SERC is in the lowest wind resource area of the country. One operational change to note, but is not expected to impact reliable performance of the bulk power system, is 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 assessment period.

Reliability Assessment Analysis
Capacity resources in SERC are expected to be able to supply the projected firm demand with adequate margin throughout the period. The projected long-term reserve margins under various definitions are reflected in SERC Figure 2.

Reported Proposed, Potential, and Existing capacity, along with the necessary transmission system upgrades, will satisfy reserve margin needs through 2018. The outcomes in terms of resource adequacy is highly dependent on regulatory support for generation expansion plans, new state, local, and federal environmental regulations impacting operation of existing generating resources; state and local environmental and siting process regulations as they influence the development of new generating resources. As can be seen in SERC Figure 1, the range of potential outcomes is quite wide, particularly for the out years. Note that year-to-year comparisons with prior reports are not possible due to the changes in the definitions NERC specifies for generation status. Additionally, the margin calculation basis has changed from Capacity Margin to Reserve Margin making comparison difficult.

SERC Figure 2: 2009 LTRA SERC Region - Reserve Margin Comparison



In order to address unexpected fuel interruptions due to resource unavailability, SERC utilities with large amounts of gas-fired generation connected to their systems have in past years conducted electric-gas interdependency studies. Also included, for each of the major pipelines serving the service territory, was an analysis of the expected sequence of events for the pipeline contingency, replacing the lost generation capacity, and assessment of electrical transmission system adequacy under the resulting conditions. Some generating units have made provisions to switch between two separate natural gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources serving load in the Region further reduces the Region's risk.

Current projections indicate the fuel supply infrastructure for the near-term planning horizon is adequate even considering possible impacts due to weather extremes. New international gas supplies are continuing to emerge in the U.S. market, positively impacting fuel inventories. While fuel deliverability problems are possible for limited periods of time due to weather extremes such as hurricanes and flooding, assessments indicate that this should not have a significant 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.

In aggregate, the utilities in the SERC Region expect 20,595 MW of Future, Planned capacity to be placed in service between now and 2018. The projected 2009 summer Reserve Margin for the SERC Region members is 25.1 percent declining to 14.9 percent by 2018 indicating capacity resources in SERC are expected to be adequate to supply the projected firm demand.

To understand the extent of generation development in the Region, it is instructive to examine the amount of generation connected to the transmission systems for the upcoming summer season. The results of the 2009 SERC Generation Plant Development Survey showed an existing generating capability of 264,300 MW connected in the Region as of December 31, 2008.

SERC does not implement a Regional or subregional planning reserve requirement. As described in more detail within the subregion reports, members adhere to their respective state commissions' regulations, respective ISO/RTO requirements 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.

Utilities in the SERC Region generally use varying combinations of three methods for resource adequacy assessment:

- 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, which is usually translated into an equivalent minimum-reserve guideline for use in long-range planning studies.
- Economic — An economically optimized probabilistic guideline, which 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 and 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 utilization and the impact of energy limitations on reliability.

On March 25, 2009, the SERC Board Executive Committee authorized the initiation of a Region-wide resource adequacy review. Initial reports 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 utilities in the SERC Region have entered into reserve sharing groups.

Demand response programs vary widely in design and penetration levels within the SERC Region. 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; North Carolina, Virginia, Texas, Illinois, and Missouri. At the time of this report, a negligible amount of renewable resources has been identified by utilities in the SERC Region. There are no specific changes in planning or operations related to the inclusion of renewable or variable generation projects.

There are 1,611 MW of retirements scheduled within the SERC Region by 2018 and there are no reliability concerns as a result.

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 systems within SERC have been planned, designed, and operated such that 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 transmission is obtained, the systems are planned and operated in accordance with NERC Reliability Standards to meet projected customer demands and provide contracted transmission services. Processes have been developed to ensure proper planning has been performed and the reliability of the systems within the SERC Region. The Region relies on the SERC Near-term Study Group (NTSG) and the Long-term Study Group (LTSG) to coordinate its transmission transfer capabilities to ensure that import transfer capabilities are adequate for projected 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 able to support reliable operations for the assessment period. These processes and studies are discussed in more detail in the subregion reports.

Total dual-fuel capabilities within the Region are 15.5 percent of capacity in 2009 declining to 14.7 percent of capacity in 2018. For most utilities in the SERC Region, 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 the fuel supply infrastructure and inventories for the summer period are adequate even considering possible impacts due to weather extremes.

Individual companies within SERC that have dynamic reserve criteria and dynamics; small signal and voltage issues are discussed in the subregion reports. The processes for dynamics and voltage criteria rest with each utility in the SERC Region. There is no overarching summary that can be provided except to assure that each utility involved in planning has clear criteria for voltage and transient performance.

The foregoing study process and its products establish deliverability between the subregions and to other Regions. These include reports on steady state power flow studies and dynamics/stability studies[169]. 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. [170]

The issue of aging infrastructure is common to utilities in North America. Utilities in the SERC Region generally address aging facilities in several ways, including life extension, age and condition studies, and planned replacement under their asset management programs. There are no significant reliability concerns due to aging infrastructure.

There are no significant FACTS technology projects planned by utilities in the SERC Region.

This is the first construction/planning cycle where the impacts of the economic recession are being experienced. Reduction in load forecasts in the range of one to two percent if they persist or increase may result in project cancellations in the future. There are no identified project cancellations or delays due exclusively to the economic recession at this time, however, utilities are now beginning to study the impact of their recently developed load forecasts on construction plans. It would not be unexpected for utilities in the future to report slippage in construction plans as a result of lower load forecasts.

Region Description

The SERC Region is a summer-peaking Region covering all or portions of 16 central and southeastern states[171]serving a population of over 68 million. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles. SERC 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).

[169] Small signal damping is considered in the context of stability studies by some SERC subregions

[170] Because it is considered CEII, the SERC RRS Annual Report to the Engineering Committee is available only upon request through the SERC web site at www.serc1.org.

[171] Alabama, Arkansas, Florida, Georgia, Iowa, Illinois, Kentucky, Louisiana, Missouri, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia.

SERC Subregions

Central Subregion

Demand

The 2009 aggregate summer net internal demand forecast for the utilities in the Central subregion was 40,874 MW and the forecast for 2018 is 45,288 MW. This year's forecast compound annual growth rate (CAGR) for 2009 to 2018 is 1.2 percent. This is lower than last year's forecast growth rate of 1.8 percent due to lower temperatures used for forecasting purposes, lower economic growth forecast, the addition of several new demand response and energy efficiency programs, 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 to 2018 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 extreme peaks and demand models to predict variance. For the majority of the utility 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 utilities in other SERC subregions, utilities in the Central subregion place strong emphasis on energy efficiency and consideration of renewables. During 2008 TVA announced a program with ambitious goals for efficiency and DSM, which is continuing to be developed in 2009. 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. Capacity in the categories of Existing (Certain, Other, and Inoperable), Future and Conceptual are expected to help meet demand during this time period.

SERC Table 1: Central LTRA Capacity Breakdown		
Capacity Type	**Year 2009**	**Year 2018**
Existing Certain	50,268 MW	49,422 MW
Nuclear	6,624 MW	7,153 MW
Hydro/Pumped Storage	5,115 MW	6,270 MW
Coal	23,450 MW	23,510 MW
Oil/Gas/Dual Fuel	13,722 MW	12,007 MW
Other/Unknown	13 MW	13 MW
Solar	0 MW	0 MW
Biomass	73 MW	73 MW
Wind	0 MW	0 MW
Existing Other	368 MW	1,517 MW
Existing Inoperable	0 MW	0 MW
Future capacity	168 MW	5,306 MW
Conceptual capacity	304 MW	1,134 MW

The wind resource in the Central subregion is generally unsuitable for large-scale wind generation. Twenty-nine 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 utilize 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 10-year reporting period. 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.

SERC Table 2: Central Subregion - Purchases and Sales			
Transaction Type	**Summer 2009**	**Summer 2010**	**Summer 2018**
Firm Imports (External Subregion)	699 MW	181 MW	181 MW
Firm Exports (External Subregion)	307 MW	490 MW	499 MW
Expected Imports (External Subregion)	0 MW	0 MW	0 MW
Expected Exports (External Subregion)	0 MW	0 MW	0 MW
Provisional Imports (External Subregion)	0 MW	0 MW	0 MW
Provisional Exports (External Subregion)	0 MW	0 MW	0 MW

Transmission

The tables provided near the end of this report show bulk power system transmission categorized as Under Construction, Planned, or Conceptual that is expected to be in-service for the period.

No constraints have been identified that could significantly impact reliability for the 10-year study period. System conditions may at times dictate local area generation re-dispatch to alleviate anticipated next contingency overloads. NERC TLR procedures will be applied in situations that are not easily remedied by a local re-dispatch.

There are several projects to upgrade the bulk power system under construction (scheduled by 2010 summer) to support the addition of generation at the Trimble County Generation Plant. These projects are on schedule. A new 345 kV interconnection between EON and EKPC is currently planned at W. Garrard. Construction for this interconnection is to begin in the fall of 2009 and is currently on schedule. There are several projects in the 10-year study period that are in the conceptual stage. These projects will address impacts from proposed future generation additions. The proposed projects are not needed until after 2014 summer and thus will not have problems meeting in-service target dates. Another new 345 kV line between the J.K. Smith Substation and the J.K. Smith CFB site is scheduled for completion by June 2012. This line will be constructed entirely within existing EKPC property; therefore, meeting the proposed schedule is not expected to be problematic. In-service dates are anticipated to be on target. Any delays in projects are not expected to affect reliability of the system.

Operational Issues

No major generating unit outages/retirements, generation additions, environmental/regulatory restrictions, or temporary operating measures are expected to affect the reliability of the Central subregion for the next 10 years.

Some entities within this subregion experienced drought conditions over the past several years. While rainfall in recent months has helped to improve the longstanding dry conditions across the Region, particularly in the lower Tennessee River valley, and rainfall amounts are approaching normal, runoff in some areas remains somewhat below normal indicating that ground water is still recharging. Affected entities anticipate transitioning from drought to dry limitations over the next two years.

The total nameplate rating for all units in the U.S. Army Corps of Engineers Nashville District is 914 MW. A continuing concern that has prompted the Corps to lower certain reservoir elevations and lowered water levels at the Wolf Creek dam limits 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 full capacity throughout the summer months. As a result SEPA customers have collectively reduced the total schedule to 554 MW for the upcoming summer season.

To address operational measures that are available if peak demands are higher than expected, utilities within the subregion perform studies based on both normal and extreme projected peak conditions. No unique problems from recent studies have been observed. Monthly, weekly, and daily operational planning efforts take into consideration demand and unit availability. This helps address any inadequacies and mitigate their risks. No operational changes are expected by the utilities in this subregion from the integration of variable resources. No unusual operating conditions are anticipated for the next 10 years.

Resource Assessment Analysis

Projected net capacity reserve margins for utilities in the subregion as reported between the years 2009 to 2018 are from 19.5 percent to 25.7 percent over the 10-year period. There is no Regional, subregional, state, or provincial reserve margin requirement for this subregion.

The reserve margin analyses in company-integrated resource plans incorporate sensitivities on load, unit availability, purchase power availability, unserved energy cost, and varying reserve margin levels. 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 10 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. Studies show that by the use of these procedures and resources, capacity is expected to meet demand for the upcoming 10-year period.

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.

Significant changes from last year's assessment to the 2009 to 2018 assessment are minimal. Utilities noted that for this year's report forecasted growth in demand is lower than the previous forecast. The key factors relating to the change were a lower economic growth forecast and the addition of several new demand response and energy efficiency programs. In addition, Spurlock generating unit 4 will be available with net capacity of 268 MW and additional nuclear capacity at Watts Bar unit 2 (scheduled for a 2012 COD) will be available in the next 10 years. Utilities also note that variable capacity, energy only, and transmission-limited resources do not contribute to reserve margin calculations in their assessments. Most utilities only count firm contract purchases (both generation and transmission) toward 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.

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 and East Kentucky), Ohio, and the Illinois Basin (West Kentucky, Indiana, and 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 periods. Multiple contracts are in place for local coal from area mines.

As noted above, the Central subregion experienced a severe drought in recent years, which seems to be moderating. Repair work on the Wolf Creek Dam is likely to continue for several more years. While the after-effects of the 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.

No generating unit retirements are planned for the next 10 years that could have significant impact on reliability. There are no renewable portfolio standards imposed by the states in this subregion.

Generation deliverability is assessed in many ways by the utilities within the subregion. Some companies consider all their generating resources within their control area and purchased transactions are either sourced from within the control area or adequate firm transmission is purchased outside the control area to deliver the power into the control area. Some companies perform transfer analysis screening studies with differing generation sources to determine if there still exists sufficient transmission capacity under a single contingency to import load requirements with one generator offline. Monthly, weekly, and real-time planning efforts are performed along with maintenance programs to ensure resources are being counted to meet the resource margins. These resource margins are expected to be sufficient and deliverable to meet load requirements.

Companies within the subregion maintain individual criteria to address any problems with stability issues. Recent stability studies identified no 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 implemented by utilities on an individual basis. Utilities generally follow the procedure of making sure that the steady-state operating point be at least five 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 voltage stability will be maintained via Q-V analysis. No additional UVLS schemes are planned for installation during the assessment period. TVA has UVLS protection schemes installed in two areas of the system for the purpose of limiting a potential wider area under-voltage event. The non-coincident peak demand served from the substations equipped with UVLS totals approximately 450 MW.

In order to prepare for catastrophic events, utilities depend on their transmission system interconnections, reserve sharing, short-term market sharing, and minimum reserve margins. If these techniques are not sufficient some utilities use voluntary load shedding and energy emergency criteria procedures as part of their emergency processes.

Guidelines to address on-site, spare generator step-up (GSU) and auto transformers, and use of standardized designs to aid interchangeability are common among the utilities in this subregion. Existing practices to accomplish these procedures range from maintaining at least one spare transformer for each unique high voltage-low voltage ratio for both GSUs and autotransformers to transformer leasing programs. The nameplate capacity of these spares is selected to at least match the highest capacity required, based on generator output for GSUs and on-system flows for autotransformers. The location at which the spares are stored is selected based upon the criticality of the energized transformer and the ability to quickly move the spare into a location if a failure occurs. In some cases, spares are stored at a power plant or substation where it is imperative to quickly replace a failed transformer. In other cases, spares are stored at a substation or service center due to a central location and ease of access. Central subregional companies continue to explore potential partnership opportunities with other utilities regarding spares.

Most utilities within the subregion perform planning studies for the NERC Reliability Standards TPL–001, TPL–002, TPL–003, and TPL–004 on an annual basis. Recent studies are being performed during the time of this report's publishing. 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 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

Companies within this subregion have various aging infrastructure programs. These programs periodically inspect, test, and evaluate maintenance procedures on transmission components that could impact electric service reliability. Through these programs several projects are funded with the purpose of replacing problematic or obsolete equipment. No reliability impacts are anticipated due to aging infrastructure.

No impacts on reliability resulting from the current economic conditions have been reported by utilities in the Central subregion for the next 10 years.

Delta Subregion

Demand

The 2009 aggregate summer net internal demand forecast for the utilities in the Delta subregion was 27,178 MW and the forecast for 2018 is 31,438 MW. This year's forecast compound annual growth rate (CAGR) for 2009 to 2018 is 1.6 percent. This is lower than last year's forecast growth rate of 1.9 percent due to customer use patterns, economic slowdown, and changes in commercial/industrial/wholesale load. The forecast assumes 10-year normal weather, normal system growth, historical data, and future economic/demographic conditions. 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 the M&V program will be used to fine tune energy efficiency programs and determine each program's cost effectiveness. The current forecast includes energy efficiency programs that have received regulatory approval and have been 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 the scenarios developed within the subregion were reported to be based on an assumption of economics and extreme weather conditions. The extreme weather conditions analyzed were 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. Capacity in the categories of Existing (Certain, Other, and Inoperable), Future, and Conceptual are expected to help meet demand during this time period.

SERC Table 1: Delta LTRA Capacity Breakdown

Capacity Type	Year 2009	Year 2018
Existing Certain	38,198 MW	34,406 MW
Nuclear	5,244 MW	5,244 MW
Hydro/Pumped Storage	304 MW	304 MW
Coal	8,611 MW	8,611 MW
Oil/Gas/Dual Fuel	24,014 MW	20,252 MW
Other/Unknown	0 MW	0 MW
Solar	0 MW	0 MW
Biomass	0 MW	0 MW
Wind	0 MW	0 MW
Existing Other	2,342 MW	3,810 MW
Existing Inoperable	1,953 MW	4,630 MW
Future Planned	33 MW	676 MW
Future Other	0 MW	538 MW
Conceptual capacity	0 MW	2,800 MW

Resources are evaluated based on the capability to meet required reliability requirements and economics. Future planned capacity additions are built into company portfolios but variable capacity are not counted as capacity to meet reliability requirements.

Capacity Transactions on Peak

Delta subregion utilities expect the following imports and exports for the 10-year period 2009 to 2018. 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 to be backed by firm transmission service and are tied to specified generators.

SERC Table 2: Delta Subregion - Purchases and Sales			
Transaction Type	**Summer 2009**	**Summer 2013**	**Summer 2018**
Firm Imports (External Subregion)	1,927 MW	1,683 MW	1,533 MW
Firm Exports (External Subregion)	1,692 MW	454 MW	454 MW
Expected Imports (External Subregion)	0 MW	0 MW	0 MW
Expected Exports (External Subregion)	0 MW	0 MW	0 MW
Provisional Imports (External Subregion)	0 MW	0 MW	0 MW
Provisional Exports (External Subregion)	0 MW	0 MW	0 MW

Transmission

The tables provided near the end of this report show bulk power system transmission categorized as under construction, planned, or conceptual that is expected to be in-service for the period.

No transmission constraints are expected to significantly impact bulk system reliability for the period. Some utilities are expecting to utilize 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.

For details on Level 3 Energy Emergency Alerts (EEA-3s) in the Acadiana load pocket area, see the Transmission section of SPP's Regional Reliability Self-Assessment.

Operational Issues

No reliability concerns are anticipated for the 10-year period as a result of operational issues from the integration of variable resources or distributed resources. There are no major generating unit outages or transmission facility outages planned which would impact bulk system reliability for the period. There are also no local environmental, regulatory restrictions, or unusual operating conditions expected that might impact reliability.

Results from the ERAG-sponsored 2009 Summer MRO-RFC-SERC West-SPP Inter-Regional Transmission System Assessment indicate potential transmission transfer issues between the Delta subregion and some neighboring Regions involved in the study. The areas of interest from this study indicate that the First Contingency Incremental Transfer Capability (FCITC) from the Delta subregion to neighboring interfaces SPP and MRO "zero."

These transfers are primarily limited by 161 kV transmission facilities on the Entergy–Southwest Power Pool interface for the outage of the ANO–Ft. Smith 500 kV line, which is a tie line between Entergy and Oklahoma Gas & Electric. The flow on Entergy's Russellville South–Russellville East 161 kV line and other series elements is very sensitive to generation dispatch at the Dardanelle Dam and ANO generating facilities as well as generation dispatch at facilities located in the Oklahoma Gas & Electric Balancing Authority area, and to inter–area transactions. Based on historical flows on both facilities, Entergy does not expect reliability transfers to be greatly limited by this flowgate. Although the Russellville East–Russellville South 161 kV line under the loss of the ANO–Ft. Smith 500 kV line significantly limited transfers on neighboring interfaces in the 2009 summer assessment, this flowgate was only subject to one transmission loading relief (TLR) action in 2008. To the extent that this flowgate is constrained in the 2009 summer operating season, Entergy anticipates the transmission loading relief procedure will be effective in mitigating any potential reliability concerns. Furthermore, Entergy and AEP–West are currently upgrading a transmission facility. The line upgrade is complete, but the anticipated completion date for the substation terminal equipment upgrade is fall 2009.

In addition, the following transmission facility upgrades are scheduled for completion by the 2011 winter operating season to mitigate potential loading certain transmission facilities that are located on the interface between Entergy and neighboring SPP systems:

- ANO–Russellville North 161 kV line (upgrade to at least 450 MVA)
- Russellville East–Russellville South 161 kV line (upgrade to at least 370 MVA)
- Bismarck–Hot Springs 115 kV line (upgrade to at least 120 MVA)
- Bismarck–Alpine–Amity 115 kV line (upgrade to at least 120 MVA)

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

Projected net reserve margins for utilities in the subregion as reported between the years 2009 to 2018 are from 15.0 percent to 41.5 percent over the 10-year period. Capacity resources are expected to be adequate to meet demand for the period.

There is no Regional, subregional, state, or provincial reserve margin requirement for this subregion. Many utilities base their reserve margins on NERC reference margin level. 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 that 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. It was reported that no significant changes from last year's studies were made to the current studies done for the period. Resources for the 10-year assessment are internal to the SERC Region and the Delta subregion. For the summer of 2009 the amount of external resources from outside the SERC Region serving load from within the Delta subregion is 1,262 MW; 549 MW is serving Delta load from other regions from within the SERC Region. These resources were considered to meet the reference margin level for the period.

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.

Unit retirements that could affect reliability are not expected to occur for the period. 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 10-year period.

Fuel supplies are anticipated to be adequate. Coal stockpiles are maintained at 45 or more days and 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 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 throughout the period. 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 BPS 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. UVLS programs are also used to maintain voltage stability and protect against BPS 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 five 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:

(i) 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

(ii) 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 assess compliance with NERC Reliability Standards TPL–001 – 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 BPS. 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 BPS 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.

To improve the BPS's reliability, utilities will continue to employ static var compensation (SVC) devices in order to provide reactive power support and maintain voltage stability. No other technologies have been implemented on the system to date.

Companies within the subregion have various processes and programs to address aging infrastructure on the system. These programs identify, replace, repair, or reinforce aging transmission infrastructure as necessary to maintain and improve reliability. Some of the mitigation programs that have been implemented include: circuit switcher replacements, relay improvements, high voltage and low voltage breaker replacements, OSMOSE pole inspection and treatment, shield-wire replacement, wood-pole replacement, transformer life extension, remote terminal unit (RTU) retrofits, and substation programs which involve programmatic replacement of aging substation infrastructure not covered in other programs (e.g., metering Current Transformers and Potential Transformers). There are no reliability concerns or impacts expected to be addressed during the assessment period.

Some Delta subregion utilities have critical spare generator step-up and auto transformers that are kept on site and are shared between plants. Participation in sharing programs are common around the subregion with neighboring utilities.

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 Subregion

Demand

The 2009 aggregate summer net internal demand forecast for the utilities in the Gateway Sub-Region was 18,947 MW and the forecast for 2018 is 20,817 MW. This year's forecast compound annual growth rate (CAGR) for 2009 to 2018 is 1.1 percent, which is the same as last year's 2008 to 2017 CAGR. The Gateway subregion's peak is reported on a non-coincident basis.

As mentioned above, the forecast growth rate is expected to be the same as last year's however, there are differences that may result in a decreased growth rate, as noted below. 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 as a result of 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 more normal operation by 2010, providing significant immediate growth.

The forecast load growth in following years is lower because of price elasticity and efficiency efforts. Some Gateway 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 for the Gateway subregion over the forecast horizon, which would 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 customer classes combined with the immediate growth from the return of the outaged industrial customer load would result in a decreased growth rate instead of an unchanged growth rate from last year's forecast. Differences in forecast are also related to economic conditions. Gateway utilities have seen a significant deterioration in the industrial load and, to a lesser extent, in the commercial load as a result of the poor economic conditions. The industrial load decline will likely be reflected in future forecasts because of automobile plant closures and the impact on other businesses in the subregion that support the automotive industry.

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, historical temperature and weather pattern information (pessimistic and optimistic conditions) are considered individually by each subregion utility.

Gateway members 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, and 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 adequate capacity reserves and low energy prices. Some subregion members address demand response as voltage reduction to customer loads served from member distribution systems. Behind-the-meter generation is also available from some 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. In addition, public appeals for conservation can be implemented across the subregion.

Generation

Companies within the Gateway subregion expect to have the following capacity on peak: Capacity in the categories of Existing (Certain, Other, and Inoperable), Future, and Conceptual are expected to help meet demand during this time period.

SERC Table 1: Gateway LTRA Capacity Breakdown		
Capacity Type	**Year 2009**	**Year 2018**
Existing Certain	24,453 MW	24,921 MW
Nuclear	2,262 MW	2,262 MW
Hydro/Pumped Storage	379 MW	819 MW
Coal	13,998 MW	13,863 MW
Oil/Gas/Dual Fuel	7,502 MW	7,502 MW
Other/Unknown	266 MW	266 MW
Solar	0 MW	0 MW
Biomass	0 MW	0 MW
Wind	100 MW	5,200 MW
Existing Other	811 MW	811 MW
Existing Inoperable	466 MW	65 MW
Future Planned	966 MW	1,248 MW
Future Other	0 MW	0 MW
Conceptual capacity	0 MW	0 MW

The generation resources to serve the retail loads for the period are predominantly located within the Gateway subregion or within 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 MISO considering a metric of one-day-in-10 years. The Illinois Power Authority has no long-term capacity contract requirements, but would follow the planning reserve requirements of the MISO. Planned retirements include the 76 MW City Water, Light and Power, Lakeside plant in 2009.

The MISO generation interconnection queue was polled to determine possible future/conceptual resources. At this time, wind and solar plants are not connected to the transmission system in the subregion, but 100 MW of wind generation is expected to be connected later in 2009. By 2018, over 4,100 MW of additional merchant wind generation is proposed to be connected in the Illinois area and 1,100 MW of merchant wind generation is proposed to be connected in the

Missouri area of the Gateway subregion. 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.

Large projected capacity additions in the subregion include the new CWLP Dallman coal-fired generator #4 (200 MW) in fall of 2009, the return of the Ameren Taum Sauk pump storage plant (440 MW) in 2010, and the Prairie State two-unit coal-fired plant in 2011 and 2012 (1,650 MW total). Two coal gasification/combined cycle plants are also proposed by 2014, which would add over 1,000 MW of capacity to the subregion totals. The Ameren Callaway nuclear unit #2 (1,650 MW in 2018) has been put on hold indefinitely as a result of failure to repeal the existing legislation that bans recovery of Construction Work in Progress funds until the plant is in service.

Capacity Transactions on Peak

The Gateway subregion reported the following imports and exports for the 10-year assessment period. 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.

SERC Table 2:Gateway Subregion -Purchases and Sales

Transaction Type	Summer 2009	Summer 2013	Summer 2018
Firm Imports (External Subregion)	498 MW	299 MW	299 MW
Firm Exports (External Subregion)	4,645 MW	1,552 MW	1,552 MW
Expected Imports (External Subregion)	0 MW	0 MW	0 MW
Expected Exports (External Subregion)	0 MW	0 MW	0 MW
Provisional Imports (External Subregion)	0 MW	0 MW	0 MW
Provisional Exports (External Subregion)	0 MW	0 MW	0 MW

Transmission

The tables provided near the end of this report show BPS transmission categorized as under construction, planned or conceptual that is expected to be in-service for the period.

As shown in Table 3 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, Illinois. 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.

Table 5 shows EHV transformer additions planned and proposed for the Gateway subregion. A number of transmission additions are in the conceptual phase of the transmission planning process. These and other transmission additions offer increased access to energy markets, increased interregional incremental transfer capability, address local reliability and generator deliverability concerns, and provide for additional flexibility in responding to developing RPS requirements, evolving climate change legislation, and future changes to NERC Reliability Standards.

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, Illinois area and provide transmission outlet capacity for the CWLP Dallman 4 generating unit #4 (200 MW). The new Hamilton-Norris City 138 kV line will provide for a second 138 kV supply to the SIPC Hamilton 138/69 kV substation.

Phasor measurement equipment is installed at various plants around the subregion to assist in providing 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 for loss reduction, transmission system flow control, and voltage control.

Operational Issues

No reliability problems are anticipated on the Gateway transmission system for the period. The City of Springfield-CWLP reported that its Dallman generator unit 1, which experienced an explosion in 2007 that compromised 86 MW, is now back in service. The new 200 MW Dallman 4 coal-fired unit will be undergoing testing during the summer of 2009 and is expected to be in commercial operation by October 2009. 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. No operational changes or concerns are expected to result from distributed resource or integration of variable resources during peak conditions.

Operations Planning studies performed in the subregion use both 50/50 and 90/10 load forecasts. 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 last year’s 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. Coordination issues between MISO and PJM can also lead to congestion along their interface in Illinois. The addition of wind generation in the Gateway subregion and surrounding areas to the north and west may exacerbate the transmission loading concerns, particularly during off-peak conditions. 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 wind output may also be required. Some base load generation might be forced off during minimum load conditions if too much generation would be available to serve the load.

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

Projected net reserve margins for utilities in the subregion as reported between the years 2009 to 2018 are from 7.2 percent to 24.6 percent over the 10-year period. There is no Regional, subregional, or state reserve margin requirement for this subregion. Gateway subregion utilities have traditionally tried to maintain a planning reserve margin of at least 15 percent, but this threshold has been reduced to a minimum of 12.7 percent based on the LOLE studies performed by the MISO considering a metric of one-day-in-10 years. Capacity reserves are evaluated for summer conditions.

The low reserve margin reported prior to 2009 summer was less than the MISO resource adequacy requirement, and was based on the reported load, and the preliminary transactions and resources obtained for the Gateway subregion utilities at that time. It was expected, but without assurances, that the MISO market mechanisms would fill this gap as the summer progressed. The low reserves reported are directly attributed to the timing of the data reporting process, which is 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, issued an RFP for capacity for the summer of 2009 and beyond. The capacity resources acquired under the RFP would comply with the resource adequacy requirements of the MISO Open Access Transmission and Energy Markets Tariff. The MISO Tariff requires that, for the planning year beginning June 1, 2009, each LSE 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 one day in ten years is currently 12.7 percent for loads in the Gateway subregion. After completion of the capacity procurement process, adequate resources and reserves would be secured to reliably supply the Gateway subregion load for the summer of 2009 and beyond.

The MISO resource adequacy and operational procedures can be found in the MISO Resource Adequacy Business Practice Manual. A 50/50 load forecast 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.

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. Capacity resources are also available within MISO. Based on past experience, resources are expected to be adequate for the upcoming peak-demand summer assessment season. A small amount of interruptible load may be available for curtailment, along with voltage reduction to reduce the subregion load. Appeals for voluntary load conservation from the MISO and Gateway utilities would also be available if needed to cover capacity shortages. If there are generation deficiencies, procedures are available at the MISO to reduce load across the MISO footprint to cover capacity shortfalls.

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. Currently, MISO does not require its LSE's to obtain generation reserve commitments beyond one planning year, but MISO and its members are in the process of developing a long-term planning reserve margin program. The MISO members are also 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 over the next several years. The amount of external resources outside the Region within Gateway was 498 MW and 1,687 MW outside the subregion for the summer of 2009. These resources were considered to meet the reference margin level for the period.

Based on data from the MISO generation interconnection queue, over 5,000 MW of wind generation is proposed to be connected in the Gateway subregion by 2018. Presently, over 57,000 MW of wind generation is proposed to be connected throughout the MISO footprint over the next 10 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 reliability is not impacted. Several utility policies take into account contracts with surrounding facilities, alternative transportation routes, and alternative fuels. These practices help to ensure balance and flexibility to meet 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 two 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 transmission capacity is sufficient to make the generation deliverable. Once MISO grants Network Resource (fully deliverable) status, it cannot be revoked. Generators that are determined not to be fully deliverable can request studies be performed to determine what transmission upgrades are required to ensure generator deliverability[172]. 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 transmission planning criteria.

[172] The Midwest ISO Transmission Expansion Plan (MTEP) may be found at: http://www.midwestiso.org/publish/Folder/3e2d0_106c60936d4_-75240a48324a

Utilities around the subregion have various ways of addressing the need and acquisition of spare generator step-up (GSU) and auto-transformer capacity. Some utilities follow a practice of requiring major generating units (300 MW and greater) to have spare GSUs. Other companies have procedures to periodically check with vendors regarding the availability of suitable replacement transformers. Some Gateway utilities are acquiring additional spare EHV transformers to meet their internal needs and the requirements of the Edison Electric Institute's-Spare Transformer Equipment Program (EEI-STEP) pool of spare transformers for catastrophic conditions. Participation in spare transformer sharing programs for normal equipment failures was not reported within the subregion.

Planning processes to address catastrophic events are commonly used around the subregion. One example of these processes is maintaining a sufficient coal inventory to handle a coal disruption. Another example of catastrophic planning around the subregion would be that gas-fired generation is supplied by multiple pipelines, thus the disruptions of a single pipeline would not have a significant impact. Utilities around the subregion also have a large number of interconnection points and are members of MISO, thus a problem with a single import path is not expected to impact reliability. Contingency analyses to meet the NERC TPL standards and local planning criteria are performed annually by the larger members in the subregion. Extreme disturbance studies and incremental transfer capability studies are also performed by utilities in the subregion. A robust transmission system with a diverse portfolio of capacity resources, including company-owned generation, member/municipal-owned generation, and contractual agreements, are also part of the planning process to ensure a reliable system for the Gateway subregion members.

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 model and a 2013 winter model were also used for the near-term assessment. No cascading is expected to occur, even for extreme contingency conditions. 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. Various utilities around the subregion also work with the SERC Near-term Study Group and Long-term Study Group in performing transmission assessment studies to comply with NERC TPL Standards.

To address transient stability modeling issues, Gateway 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 five 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 double-circuit tower outages during peak conditions, but widespread outages are not expected. Plans to build new transmission lines to mitigate the contingency are proceeding, and 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 reliability issues or concerns within this subregion.

No UVLS programs are expected to be installed within the assessment period.

Utilities within the subregion have been active in the replacement of older substation equipment as the need for system upgrades arise. Some utilities have limited transmission asset management programs to address concerns for older circuit breakers and system protection equipment that require more than normal maintenance for continued operation. As a result of these programs, Gateway utilities report there are no significant infrastructure needs requiring immediate mitigation to address equipment aging outside of the normal infrastructure maintenance to ensure reliability. Additionally, no negative impacts on reliability are expected for the period due to economic conditions.

Southeastern Subregion

Demand

The 2009 aggregate summer net internal demand forecast for the utilities in the Southeastern Subregion was 47,789 MW and the forecast for 2018 is 58,505 MW. This year's forecast compound annual growth rate (CAGR) for 2009 to 2018 is 2.3 percent. Growth rates are predicted to be less than last year's rate of 2.5 percent. 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 utilize in order to reduce their monthly household electric use and to provide methods on how to wisely use electricity 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 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 the 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.

Peak demand forecast is based on normal weather conditions and uses normal weather, normal 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 in the Southeastern subregion expect to have the following capacity on peak. Capacity in the categories of Existing (Certain, Other, and Inoperable), Future, and Conceptual are expected to help meet demand during this time period.

SERC Table 1: Southeastern LTRA Capacity Breakdown

Capacity Type	Year 2009	Year 2018
Existing Certain	56,659 MW	54,725 MW
Nuclear	5,897 MW	5,947 MW
Hydro/Pumped Storage	4,949 MW	4,949 MW
Coal	24,551 MW	23,694 MW
Oil/Gas/Dual Fuel	20,552 MW	20,253 MW
Other/Unknown	0 MW	0 MW
Solar	0 MW	0 MW
Biomass	0 MW	0 MW
Wind	0 MW	0 MW
Existing Other	9,043 MW	9,187 MW
Existing Inoperable	0 MW	0 MW

Future Planned	0 MW	6,707 MW
Future Other	0 MW	1,889 MW
Conceptual capacity	0 MW	3,917 MW

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 a 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 is not commonly included in calculations.

Capacity Transactions on Peak

Southeastern utilities reported the following imports and exports for the 10-year reporting period. 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.

SERC Table 2:Southeastern Subregion - Purchases and Sales

Transaction Type	Summer 2009	Summer 2013	Summer 2018
Firm Imports (External Subregion)	4,029 MW	5,408 MW	7,990 MW
Firm Exports (External Subregion)	1,943 MW	2,509 MW	1,562 MW
Expected Imports (External Subregion)	0 MW	0 MW	0 MW
Expected Exports (External Subregion)	0 MW	0 MW	0 MW
Provisional Imports (External Subregion)	0 MW	0 MW	0 MW
Provisional Exports (External Subregion)	0 MW	0 MW	0 MW

Transmission

The tables provided near the end of this report BPS transmission categorized as under construction, planned, or conceptual that is expected to be in-service for the period.

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. No new technologies are planned for the near future that will significantly impact transmission reliability.

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 during this assessment period. Generator maintenance for the units within the Southern Control Area does not normally occur during the summer months. No generator unit maintenance outages are scheduled for the summer of 2009 or reported to be expected during the summer period. 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 Balancing Area have several operating limits related to air and/or 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. Utilities within the subregion experienced drought 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. Additionally, no unit retirements are expected for the assessment period that will affect system reliability within the subregion.

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 and are updated on a monthly basis. Additional reliability studies are conducted on a two-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

Projected net reserve margins for utilities in the subregion as reported between the years 2009 to 2018 are from 12.3 percent to 22.9 percent over the 10-year period. There is no Regional, subregional, state, or provincial reserve margin requirement for this subregion, other than the state of Georgia as discussed below. 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 Power Purchase Agreement's. 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 (less than three) and 15 percent long-term (three years or more) reserve margin levels for investor-owned utilities. Requirements for long-term and short-term margins are not treated differently. 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, 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 summer 2009 are expected to be within the range of 15–33 percent for utilities within the subregion; it is not expected to drop below 15 percent. Even though utilities utilize 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 NERC Reference 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. However, energy-only and transmission-limited resources are not included in reserve margins within the study. Additionally, studies have been performed to include a 2008 resource adequacy analysis assuming an 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 maintain adequate operating reserves.

The amount of external resources (outside the Southeastern Region but within the SERC subregion) was 2,034 MW for the summer of 2009. During this timeframe, Southeastern utilities reported 5 MW outside the subregion. These resources were considered to be able to meet the criteria or target margin levels for the summer of 2009.

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. Other than hydro, renewable resources are not yet utilized 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 also appears to be a hurdle for renewable resource developers causing project cancellations despite regulatory incentives. Due to the uncertainty driven by the cancellations, some companies limit the renewable project capacity represented in their integrated resource plan to 50 percent of the proposed project amount. Due to the small amount of proposed renewable 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 are 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 capacity during the summer months and the interface studies demonstrating deliverability. Only limited amounts of external resources are expected to be required during the assessment period. 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. 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 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 fuel vulnerability is not an expected reliability concern for the period. The utilities have a highly diverse fuel mix to supply its demand, including nuclear, Powder River Basin (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 storage facilities are filled well in advance of hurricane season (by June 1 of each year). These tactics help 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. This will result in below-normal hydro output during the summer of 2009. Even with this reduction, peak season estimated reserve margin will remain well above the target level. Mitigation plans, if required, would include possible market purchases and, in extreme situations, shedding non-firm load.

The Southeastern subregion does not have subregional criteria for dynamic, voltage, or 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 five 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 five 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 performed 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 approximately 82 percent of peak summer load conditions.

A 2,250 MW UVLS scheme has been installed in northern Georgia. The scheme was installed to help meet three-phase faults with breaker failure contingencies performed for the reliability assessment of the system. No plans to install more schemes have been reported for the period.

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–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.

To prepare for catastrophic events, utilities within the subregion use various tactics. Processes and guidelines within coal, gas, and transmission use were areas that companies saw as the most critical. To address coal, some resource adequacy studies around the subregion evaluate the ability to meet peak load while considering the capability and historic probabilistic limitations of the import interfaces. A special scenario of the study is performed to assess the ability of the system to sustain a credible, worst-case catastrophic pipeline failure event. Gas is assessed by some utilities through firm gas supply contracts with over 25 natural gas suppliers from multiple regions, including the Gulf of Mexico, mid-continent, and liquefied natural gas. In addition, over 100 NAESB contracts with suppliers and contracts with natural gas storage service providers ensure protection against short-term supply interruptions. The gas pipeline companies and gas storage providers communicate any facility outages or issues in advance with company gas employees through informational postings on their Web sites or through e-mails. As described above, companies regularly perform transmission studies considering loss-of-pipeline, extreme event (TPL-003 and 004), and infrastructure security studies. Various contracts (Master Interchange and Reserve Sharing Agreements, Interruptible Load Contracts, Reserve Margins, Dual Fuel Capabilities, etc.) are in place to provide assistance during emergency conditions. The purpose of all these is to address vulnerability to catastrophic events and the development of appropriate mitigation plans. The general conclusion is the system is capable of weathering many potential catastrophic events with minimal impacts on neighboring systems.

Formal guidelines for on-site, spare generator step-up (GSU) or auto transformers are not common around the subregion. However, it is common for companies to have spare GSU's onsite at some facilities and participate in a sharing program at other facilities at their discretion.

No negative impacts on reliability are expected to result from aging infrastructure or the economic conditions in the Southeastern subregion.

VACAR Subregion

Demand

The 2009 aggregate summer net internal demand forecast for the utilities in the VACAR Sub-Region was 62,083 MW and the forecast for 2018 is 72,814 MW. This year's forecast compound annual growth rate (CAGR) for 2009 to 2018 is 1.8 percent. This is lower than last year's forecast growth rate of 1.9 percent. The economic recession is expected to cause slowed load growth. 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 1–5 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 the 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 DSM 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 effects 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 period.

SERC Table 1: VACAR LTRA Capacity Breakdown		
Capacity Type	**Year 2009**	**Year 2018**
Existing Certain	73,145 MW	71,097 MW
Nuclear	14,870 MW	14,870 MW
Hydro/Pumped Storage	9,745 MW	9,810 MW
Coal	20,847 MW	19,757 MW
Oil/Gas/Dual Fuel	26,985 MW	26,396 MW
Other/Unknown	249 MW	246 MW
Solar	0 MW	0 MW
Biomass	141 MW	141 MW
Wind	0 MW	0 MW
Existing Other	1,784 MW	1,781 MW
Existing Inoperable	45 MW	45 MW
Future Planned	1,020 MW	6,658 MW
Future Other	0 MW	0 MW
Conceptual capacity	0 MW	3,748 MW

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 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 it will take the following actions in 2009 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 10-year assessment period. These sales and purchases are external and internal to the Region and subregion and help ensure resource adequacy for the utilities within the VACAR area. All purchases are backed by firm contracts for both generation and transmission

SERC Table 2: VACAR Subregion - Purchases and Sales			
Transaction Type	**Summer 2009**	**Summer 2013**	**Summer 2018**
Firm Imports (External Subregion)	1,648 MW	1,609 MW	1,370 MW
Firm Exports (External Subregion)	150 MW	100 MW	100 MW
Expected Imports (External Subregion)	0 MW	0 MW	0 MW
Expected Exports (External Subregion)	0 MW	0 MW	0 MW
Provisional Imports (External Subregion)	0 MW	0 MW	0 MW
Provisional Exports (External Subregion)	0 MW	0 MW	0 MW

Of these imports/exports, very few are associated with Liquidated Damage Contracts (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

The tables provided near the end of this report show BPS transmission categorized as under construction, planned, or conceptual that is expected to be in-service for the period.

The majority of the entities within the subregion do not foresee any transmission concerns or constraints for the period. However, impediments to building transmission continue to increase causing greater concern for completing needed transmission facilities. To help ease concerns, some companies have resorted to identifying and acquiring right-of-way needs earlier in the process schedule. 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 summer of 2009 is consistent with results identified in previous assessments.

Utilities in the subregion have employed static var compensation 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 10-year period, no summer generation outages are planned for the next 10 years. However, a major outage is planned for the spring of 2010 that will last approximately 30 days. It is not expected to impact the BPS due to the facilities generation capability. Typical planned maintenance/refuel outages are incorporated in the planning process to reliably meet demands. Short-term capacity needs to maintain an acceptable reserve margin can be met with any combination of built or purchased generation, purchase power agreements, or increased DSM.

No anticipated local environmental or regulatory restrictions that could potentially impact reliability have been identified. To ensure minimum impact to the system, PJM requires its members in VACAR to place generation 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.

A 90/10 forecast is not commonly used within this subregion, but those who do use the method reported that it is roughly five percent above the expected forecast. Sufficient 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 would 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.

No unusual operating conditions, reliability issues, or operational changes resulting from integration of variable resources were reported on recent operational planning studies of the utilities within the subregion.

Reliability Assessment Analysis

Projected net reserve margins for utilities in the subregion as reported between the years 2009 to 2018 are from 8.3 percent to 21.9 percent over the 10-year period. Resources are expected to be adequate to meet demand for the period. Although some utilities within this subregion adhere to North Carolina Utilities Commission regulations, other utilities 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 (e.g., 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. Currently, short and long-term margins are not treated differently in company calculation processes.

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 Rural Utilities Services 1710 requirements. From this analysis, resources are planned accordingly. Recent studies are expected to show the system to be adequate based on the current forecast, generation and demand side resources. Companies reported no changes from last year's study other than the effects of the downturn in the economy, which is expected to have an impact on the company's demand forecast and in-service dates for new capacity. Lower peaks and demand forecasts are expected, but the percent decrease is not known at this time. However, increases in wholesale load may offset the drop in forecasted peak and demand from the result of additional customers. Also in the current study, Duke has delayed its projected in-service date for a combined cycle facility at Buck to 2012 (from 2011) and eliminated the phase in from combustion turbine (CT) (2011) to combined cycle (CC) (2012) at Dan River to a full CC operational in 2012. Duke will continue to evaluate and optimize the timing of these projects as new information is made available.

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 reported 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 delta 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 used 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. In addition, utilities have reported that energy-only or transmission-limited resources are not incorporated in their planning processes. Some companies have reported that they are modeled when performing generator interconnection studies to check short-circuit and dynamics performance.

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 for the summer of 2009 is projected to be 543 MW.

Duke Energy reported that it has developed a timeline of expected unit 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 criterion for firm transmission to be granted. No concerns were listed as a delivery issue for the period.

Utilities within the VACAR area have reported 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 are not anticipated for the period. However, it was reported that coal demand is expected to be somewhat lower in 2009 and general demand for rail capacity is down as well. Currently coal stockpiles are adequate to meet peak demand and accommodate short-term supply disruptions. Some unit outages were also reported to be mitigated through exchange agreements or alternative fuel sources and portfolios.

Utilities within the subregion reported 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 portfolio resources and projected hydro generation and reservoir levels, capacity is expected to be adequate to meet both normal and emergency energy demands for summer 2009. 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 as well as 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.

Transmission planning practices are used in accordance with NERC TPL-001–004 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. Recent studies have identified no reliability issues. Some utilities perform an operational peak self-assessment for anticipated and extreme winter/summer conditions as well as performing interregional analysis in conjunction with their neighbors to identify potential issues that may arise between areas. No reliability issues are expected. Tests are also done to assess various stability study criteria 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 and 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 most recent 2009 summer season studies. In order to address reliability issues in the future, utilities have considered using UVLS schemes on their system. However, none of these programs are currently installed on the system during the time of this assessment.

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 period.

Utilities have addressed planning processes for catastrophic events in many ways. Some companies have procedures in place for system restoration, capacity, and emergency plans.

Other companies follow the practice of maintaining several days' worth of fuel oil at facilities in the event of natural gas disruptions. Resource portfolios are also used to address the issue. Portfolios are diversified with multiple resources mitigating the impacts of a major import path disruption. Sophisticated internal real-time systems have been developed around the system to track and analyze gas pipeline issues. These systems can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of a contingency analysis process. Depending on the advance notice, operating plans can be adjusted or emergency procedures can be implemented. For the projected summer peaks, reserve margins are such that loss of multiple units can be accommodated without threatening reliability.

Formal guidelines for on-site, spare generator step-up (GSU), or auto transformers are not common around the subregion. However, it is common for companies to have spare GSU's onsite at some facilities (for example, 500 kV and 230 kV autotransformers, nuclear plant GSU's, and medium and large power fossil/hydro GSU's, etc.) and participate in a sharing program at other facilities at their discretion

Although no expected reliability impacts are expected to occur, certain entities have reported increased changes in the numbers of new queued projects or queued project withdrawals for the future. No correlation to economic trends as to cause has been made. Aging infrastructure on the system is also not expected to affect reliability as this is considered when prioritizing projects.

SPP

Introduction

Southwest Power Pool (SPP) operates and oversees the electric grid in the southwestern quadrant of the Eastern Interconnection. SPP's Regional Transmission Organization (RTO) footprint includes all or part of nine states in the U.S. On April 1, 2009, the SPP RTO acquired three new members for which SPP will perform Reliability Coordination and Tariff Administration services: Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System. Midwest Reliability Organization (MRO) will continue to perform Reliability Assessments for these entities until a NERC Delegation Agreement is revised in 2010.

The SPP RTO anticipates consistent but slow growth in demand and energy use over the next ten years. Significant generation capacity using uncertain resources is forecasted to be available in SPP throughout the planning horizon to meet native network load needs, with certain generation resources meeting minimum Reserve Margins until 2016.

Demand

According to the most recent data, the projected annual rate of growth for peak demand in the SPP Region over the next ten years is 1.1 percent, from 44,463 MW in 2009 to 49,695 MW in 2018. In the *2008 Long-Term Reliability Assessment* report, the projected annual growth rate for the SPP Region over the 10 year period was 1.4 percent. This decrease results from some SPP members reporting reduced load forecast due to economic recessions in their respective areas.

For 2009 to 2018 the projected annual rate of growth for energy use in the SPP Region is 1.3 percent, from 211,320 GWh in 2009 to 240,513 GWh in 2018. This is slightly less than the 2008 report's forecasted growth rate of 1.5 percent.

The SPP RTO has 21 reporting members who annually provide a 10 year forecast of peak demand and net energy requirements. These forecasts are used to develop an overall non-coincident SPP RTO forecast. The forecasts are developed in accordance with generally recognized methodologies and in accordance with the following principles:

- Each member selects its own demand forecasting method and establishes its own forecast.
- Each member forecasts demand based on expected weather conditions. In the case of extreme weather, peak demand would be increased by approximately 2.9 percent.

Methods used, factors considered, and assumptions made are submitted to SPP, along with the annual forecast. Economic, technological, sociological, demographic, and any other significant factors are considered when producing the forecast.

The resultant SPP RTO forecast is a total of the member forecasts. High and low growth rates and unusual weather scenario bands are then produced for the SPP RTO Regional demand and energy forecasts. To ensure against negative impacts due to forecast error, SPP requires each member to maintain a 12 percent Capacity Margin or 13.6 percent Reserve Margin.

Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands used for assessing net capacity or Reserve Margins are based on normal weather conditions and do not include interruptible loads.

These capacity or Reserve Margin projections include the effects of demand-side response programs, such as direct-control load management and interruptible demand. Currently, the SPP RTO does not have a specific Demand Response program. However, according to SPP's Strategic Plan[173], the SPP staff along with its members plan on establishing collective knowledge to eventually include conservation and efficiency programs Intergrated Resource Planning, Demand Side Management. In the meantime, over the next 10 years, interruptible demand relief is expected to increase from 484 MW to 527 MW. These Demand Response values are based on predictions using historical data and trends; these projections do not reflect increased Demand Response as directed by FERC in the evolution of SPP's market design. Also, these projections are net values and do not indicate the increase in Demand Response to offset significant amounts of interruptible loads.

To quantify peak demand uncertainty and variability due to extreme weather, economic conditions, and other variables, SPP formed a Bandwidth Working Group. This group produced the Demand and Energy Bandwidth Report[174], which supports the current predicted growth rates and allows for up to a 1.2 percent variation in current and future predictions through the year 2012. SPP anticipates this trend will continue for the remaining study period, and is continuing this analysis process for future predictions beyond 2012.

Generation

For the 2009 to 2018 assessment period, the SPP RTO projects to have 49,362 MW Existing Certain Capacity; 8,617 MW Existing Other Capacity; 597 MW Existing Inoperable; 4,397 MW Future Capacity; and 3,305 MW Conceptual resources that are either in-service or are expected to be in-service. The Existing Certain Capacity amount from renewable plants is 217 MW (wind), 2,995 MW (hydro), and 365 MW (biomass). Existing Uncertain Capacity from renewable plants (mostly wind) is 2,040 MW. Planned Capacity for 2018 from renewable plants is 22 MW. These reported renewable resource additions in the SPP RTO do not reflect merchant wind farm development in process within SPP, incremental needs which may result from Renewable Electricity Standard (RES) mandates within the SPP Region, or public pronouncements for additional renewable expansion by SPP RTO members. Currently, the SPP RTO has requests to connect approximately 56,000 MW of generation (mostly wind) to the SPP RTO grid via the Generation Interconnection queue.

For future and conceptual capacity resources, the SPP RTO uses the Generation Interconnection (GI) and Transmission Service Request (TSR) study processes as defined in the SPP Open

[173] http://www.spp.org/section.asp?pageID=83

[174] The Demand and Energy Bandwidth Report is located: http://www.spp.org/publications/BWG_Report_2003.pdf.

Access Transmission Tariff (OATT). According to the OATT[175], at the time the Interconnection Request is submitted, the Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service. Any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customers may then elect to proceed with Network Resource Interconnection Service or proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

Purchases and Sales on Peak

A small portion of SPP's capacity or Reserve Margin depends on purchases from other Regions. Transactions purchased from other Regions for the 2009 to 2018 assessment period are 964 MW (this is a ten-year average). Based on a ten-year average (2009 to 2018), 875 MW of these purchases are firm, and 150 MW is firm delivery service from WECC administered under Xcel Energy's OATT.

SPP has 798 MW of firm sales to Regions external to SPP based on a ten-year average, including firm generation and transmission.

Transmission

The SPP Transmission Expansion Plan (STEP) establishes transmission system needs for the next ten years to meet forecasted load and all firm long term transmission service. The STEP includes a reliability assessment with different scenarios of firm transmission being sold in various directions. In addition, the SPP RTO has been performing various analyses to comply with NERC Transmission Planning (TPL) standards. SPP also developed a Balanced Portfolio study to evaluate economic transmission projects that would benefit the entire Region.

There are no known concerns about meeting the target in-service dates for the projects that are approved by the SPP Board of Directors. Assuming these projects come on-line as scheduled, there are no known transmission constraints that could impact the reliability of the SPP transmission grid. The SPP RTO has identified and issued Notifications to Construct (NTCs) for over 1,000 miles of bulk transmission lines and more than 10 transformers to address reliability and economic needs. A summary of these projects is listed in *Transmission and Transformers Tables* section of this report.

For details on Level 3 Energy Emergency Alerts (EEA-3s) in the Acadiana load pocket area, see the Transmission section of SPP's Regional Reliability Self-Assessment.

Operational Issues

The penetration of wind generation in the western half of the SPP footprint could have a significant impact on operations, due to wind's variable nature. Several avenues are being explored to provide transmission outlets for this wind energy during the next ten years, including SPP's EHV Overlay Study, the Balanced Portfolio, and the Joint Coordinated System Plan (JCSP). However, the operational impacts of wind generation to regulation and control

[175] http://www.spp.org/publications/SPP_Tariff.pdf

performance are still unknown. As the penetration rate of variable generation grows, further study will be required to mitigate any issues that arise.

Additional data collection and situational awareness has been implemented to begin assessing regulation and spinning reserve needs. SPP formed the Wind Integration Task Force in January 2009. This Task Force is responsible for conducting and reviewing studies to determine the impact of integrating wind generation into the SPP RTO transmission system and energy markets. These studies will include both planning and operational issues, and should lead to recommendations for developing new tools that may be required for the SPP RTO to properly evaluate requests for interconnecting wind generating resources to the transmission system.

The SPP RTO has been working with AMEC and Southwestern Public Service/Xcel Energy staff to investigate the operational impacts of increased wind penetration to secure reliable operations within the Southwestern Public Service (SPS) area. Due to significant existing, approved, and requested wind farm development, existing constraints in the near-term must be resolved before major transmission capability can be installed to improve internal and interface capabilities. This AMEC study of spring 2010 conditions focused on operations and reliability, and did not investigate economics associated with planned and potential wind development within and surrounding the SPS balancing authority. The study leveraged the National Renewable Energy Lab's wind data for 2004 to 2006 to simulate future scenarios for 2010. Without considering proactive wind curtailments as an option, the study concluded that operating margins within SPS would be jeopardized as wind farm development approached 1,100–1,200 MW within SPS. This is only slightly above existing wind farm levels, with more being built and another 2,000 MW of approved wind Interconnection Agreements. SPS is working with SPP to finalize operating procedures and communicate them to wind developers as a near-term solution. Consolidating the SPP RTO's balancing authorities will help facilitate wind integration in the Region, but additional changes to the SPP OATT, interconnection agreements, operating procedures, and market design may be required to maintain adequate operating margins within SPS and other portions of SPP as wind development continues.

SPP operations staff does not anticipate any environmental or regulatory restrictions that could potentially impact reliability. SPP has a substantially diverse mix of generation capacity and a sufficient expected Capacity Margin such that no reliability impacts are foreseen.

Reliability Assessment Analysis

For the 2009 to 2018 assessment period, the net capacity margin reflected by current EIA-411 data, based on Deliverable Capacity Resources, indicates SPP members should maintain a 12.8 percent capacity margin in 2009, reducing to 9.0 percent in 2018. The forecasted Reserve Margin for 2009 is 14.7 percent, reducing to 9.9 percent in 2018. These margins are expected to cover a 90/10 weather scenario.

The annual net capacity margin for SPP is greater than the required 12 percent until the year 2016, when the capacity margin will drop to 11.5 percent and the Reserve Margin to 13.0 percent. For 2017 and 2018, SPP anticipates more resources will be qualified as certain and can be counted against capacity margin.

SPP defines firm deliverability as electric power intended to be continuously available to buyers even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin) and energy. Such power must meet the same standards of reliability and availability as that delivered to native load customers. Power purchased can be considered firm only if firm transmission service is in place to deliver the power to the load serving member. SPP does not include financial firm contracts in this category. Existing long-term firm delivery is ensured by provisions in the SPP Transmission Expansion Plan, while new long-term firm delivery is ensured by Aggregate Transmission Service Studies. These procedures are included in attachments O and Z1 in the SPP OATT[176].

SPP monitors potential fuel supply limitations by consulting with its generation-owning and generation-controlling members at the beginning of each year. There are no known infrastructure issues, which could impact deliverability, as SPP is blanketed by major pipelines and railroads to provide an adequate fuel supply. Coal-fired and natural gas power plants, which make up approximately 48 and 44 percent of total generation respectively, are required by SPP criteria to keep sufficient quantities of standby fuel in case of deliverability issues. As previously stated, because hydro capacity is a small fraction of capacity for the Region, run-of-river hydro issues brought about by extreme weather are also not expected to be critical.

Significant deliverability problems due to transmission limitation are not expected, assuming all projected projects are completed on time. SPP will continue to closely monitor the issue of deliverability through the flowgate assessment analysis, and will 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 SPP staff. These scenario models reflect all the potential transactions in various directions being requested on the SPP system. The results of this study are reviewed and approved by SPP's Transmission Working Group prior to summer and winter of each study year.

According to the NERC Functional Model, the Planning Coordinator ensures a long-term (generally one year and beyond) plan is available for adequate resources and transmission within its Planning Coordinator Area. That area, which encompasses the customer demands therein, will not necessarily coincide with a Reliability Coordinator Area. A Loss of Load Expectation (LOLE) study was performed by SPP RTO staff in 2008 to meet these requirements and verify whether a 12 percent capacity margin (13.6 percent Reserve Margin) is adequate. In 2009, the SPP RTO finalized the sensitivity analysis for this study. This sensitivity addresses the impact of wind penetration in the western part of the grid. The results of this sensitivity study indicate the LOLE in the western part of the SPP system should be improved by a combination of additional generation resources (wind and fossil fuels) as well as an additional transmission line (345 kV line from Woodward District EHV to Tuco) into the Texas Panhandle. Historically, SPP has adhered to a 12 percent capacity margin/13.6 percent Reserve Margin to ensure the minimum LOLE of one occurrence in 10 years is met. Presently, the 12 percent capacity margin/13.6 percent Reserve Margin requirement (both short-term and long-term) is checked annually in the EIA-411 reporting, as well as through Regional members' supply adequacy audits. The last supply adequacy audit was conducted in 2007, and the subsequent audit is scheduled for 2012.

[176] http://www.spp.org/publications/SPP_Tariff.pdf

The SPP RTO develops an annual SPP Transmission Expansion Plan (STEP) that includes a group of projects to address Regional reliability needs for the next 10 years (2009–2018). The latest STEP was approved by the SPP Board of Directors in January 2009 and is available on the SPP.org *Engineering and Planning* section.[177] In addition to the STEP and as a part of compliance assessment process, the SPP RTO also performs a dynamic stability analysis. The latest dynamic study completed for 2009 operating conditions did not indicate any dynamic stability issues for the SPP RTO Region. The SPP Regional Entity (RE) performs an annual review of reactive reserve requirements for load pockets within the Region. Currently, the SPP RE and RTO do not have specific criteria for maintaining minimum dynamic reactive requirement or transient voltage dip criteria. However, according to the reactive requirement study scope, which was completed as a STEP process in 2008, each load pocket or constrained area was studied to verify that sufficient reactive reserves are available to cover the loss of the largest unit. The annual STEP process conducted by the SPP RTO did not indicate limited dynamic and static reactive power areas on the BPS.

As a part of the interregional transmission transfer capability study, the SPP RE participates in the Eastern Interconnection Reliability Assessment Group seasonal study group (comprised of 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 results of this study do not indicate any reliability issues for the SPP area.

SPP RTO members, along with neighboring members like Entergy from the SERC Region, have formed a Reserve Sharing Group. Members of this group receive contingency reserve assistance from other SPP Reserve Sharing Group members. SPP's Operating Reliability Working Group sets the Minimum Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be online.

The SPP RTO has an UVLS program in the western Arkansas area within the AEP-West footprint. This program targets about 180 MW of load shed during the peak summer conditions to protect the BPS against under-voltage events.

The SPP RTO anticipates a significant amount of wind capacity to be added in the SPP footprint in the western part of the footprint. Although these are predominantly energy-only resources and only a small portion of this capacity (according to SPP Criteria 12.3.5.g) will be counted as certain based on the historical trend, it would be sufficient to meet SPP's capacity or Reserve Margin requirement. No major unit retirements are planned within the next ten years.

Due to the SPP RTO's diverse generation portfolio, there is no concern about the fuel supply being impacted by the extremes of summer weather during peak conditions. If a fuel shortage is expected, SPP members are expected to communicate with SPP operations staff in advance so they can take the appropriate measures. The SPP RTO would assess if capacity or reserves would become insufficient due to the unavailable generation. If so, the SPP RTO would declare either an Energy Emergency Alert or Other Extreme Contingency and post as needed on the

[177] http://www.spp.org/publications/2007_percent20SPP_percent20Transmission_percent20Expansion_percent20Plan_percent2020080131_BOD_Public.pdf

Reliability Coordinator Information System. SPP does not conduct operations planning studies to evaluate the extreme hot weather conditions. Capacity margin criteria are intended to address load forecast uncertainty.

Energy-only resources, uncommitted resources, and transmission-limited resources are not used in calculating net capacity margin. The EIA-411 data does not include the 8,597 MW of uncommitted resources located within the SPP RTO footprint. These are reflected in the total potential resources capacity or Reserve Margin, which is considerably greater than the net capacity margin. SPP has not assessed the highest short circuit levels that have been forecasted on its 230 kV and above transmission system during the assessment period. No reliability impacts have been addressed due to aging infrastructure or economic conditions, and at this time SPP does not have any guideline for on-site, spare-generator step-up (GSU), and auto transformers.

As a Planning Authority, the SPP RE conducts reliability assessments to comply with NERC TPL standards:

- TPL-001 — The SPP Model Development Working Group (MDWG) ensures that all base case violations are addressed during Base Case development.
- TPL-002 — Using the SPP MDWG Models, Near and Long Term Analysis for N-1 contingencies are performed by SPP staff.
- TPL-003 — SPP staff performs automatic N-2 contingencies along with selected N-2 contingencies submitted by SPP members.
- TPL-004 — SPP periodically conducts reactive reserve and stability studies that address the key requirement in this standard. This standard covers the requirements of the SPP Region's planning process concerning selected catastrophic events.

Based on these studies, the SPP RE does not anticipate any near-term or long-term reliability issues that have not been addressed by mitigation plans or with local operating guides.

The Balanced Portfolio is an SPP RTO strategic initiative to develop a cohesive group of economic upgrades that benefit the SPP RTO Region, and for which costs will be allocated Regionally. Projects in the Balanced Portfolio are transmission upgrades of 345 kV or higher that will provide customers with potential savings that exceed the cost of the project. These economic upgrades will reduce congestion on the SPP RTO transmission system, resulting in savings in generation production costs. The economic upgrades may provide other benefits to the power grid, including increased reliability, lower Reserve Margins, deferred reliability upgrades, and environmental benefits due to more efficient operation of thermal assets and greater utilization of renewables[178].

The SPP Board of Directors recently approved the adoption of new planning principles and implementation of an Integrated Transmission Planning (ITP) Process. The ITP will consolidate SPP's EHV Overlay, Balanced Portfolio, and 10-year reliability assessment into one consolidated process.

---

[178] http://www.spp.org/publications/Item2 percent20- percent202009 percent20SPP percent20Balanced percent20Portfolio percent20Report percent20- percent20DRAFT_20090515-update.doc

Principles of the ITP include:

- Focus on Regional needs, while integrating local needs
- Plan will be updated every three years
- Goal is to build a robust grid to meet near- and long-term needs
- Will result in comprehensive list of needed projects for SPP Region over next 20 years
- Plan the transmission backbone to connect known load centers to known or expected larger generation sites
- EHV transmission backbone should connect transmission between SPP's west and east Regions and strengthen existing ties to the Eastern Interconnection, with options for interconnecting to the Western grid
- Planning horizons will be 5, 10, and 20 years
- Will position SPP to proactively prepare and quickly respond to national priorities that may require additional consideration

There are no other Region-specific issues other than the one described above for SPP at this time.

Region Description

The Southwest Power Pool (SPP) Regional Transmission Organization (RTO) 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. The SPP RTO manages transmission in eight of those states. SPP's footprint includes 26 balancing authorities and 47,000 miles of transmission lines. The SPP RTO has 54 members that serve over 5 million customers. SPP's RTO 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 SPP.org.

NPCC

Introduction

Recognizing their diversity, the adequacy of NPCC is measured by assessing the five subregions, or areas, of NPCC: the Maritimes 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 (ISO New England Inc.), New York (New York ISO), Ontario (the Independent Electricity System Operator), and Québec (Hydro-Québec TransÉnergie). The Maritimes Area and Québec are predominantly winter-peaking systems. The Ontario, New York, and New England Areas are summer-peaking systems. Consequently, the mix of winter and summer peaking areas would make an NPCC-wide comparison of year-to-year peaks misleading. Comparisons for the individual subregions follow. The expected growth, together with the overall reliability assessment of the projected transmission and resources, follows individually for the Maritimes Area, New England, New York, Ontario, and Québec.

Four of the five NPCC subregions meet the NPCC adequacy criterion of disconnecting firm load due to resource deficiencies no more than 0.1 day-per-year on average. Québec, over the last three years of the assessment, must identify a total of 2,800 MW of resources.

In all five areas, lowered economic expectations together with aggressive energy efficiency programs have essentially leveled or reduced the anticipated growth in demand for the ten-year study period. The impact of the economic recession and the increased efforts at energy efficiency can be seen in the comparisons of 2008 to 2009 load growth:

Table NPCC 1: Average Annual Load Growth Projection

	2009	2008
Maritimes	0.40%	0.90%
New England	1.20%	1.20%
New York	0.68%	0.94%
Ontario	-0.70%	-0.90%
Québec	1.04%	0.80%

Québec is targeting 11.0 TWh in recurring energy savings by 2015.

Ontario is progressing towards the elimination of all coal-fired generation by the end of 2014. The 1,250 MW Outaouais back-to-back HVdc interconnection, the double circuit Bruce to Milton 500 kV line and 500 kV transmissions lines from Sudbury to Toronto and Sudbury to Mississagi are to be planned over the study period.

Demand

The following tables demonstrate the NPCC total demand over the ten-year study period recognizing the load diversity among the areas as described above, both winter and summer peak demands are presented, together with a table for total GWh for each study year:

NPCC 2009 Long-Term Reliability Assessment Summary- Projected "Total Internal Demand" (Summer)						
Study Year	Maritimes	New England	New York	Ontario	Québec	NPCC Total
2008 Actual	3,435	27,765	32,432	24,195	20,969	108,796
2009	3,499	27,875	33,452	24,351	20,621	109,798
2010	3,448	28,160	33,441	24,160	20,954	110,163
2011	3,437	28,575	33,693	24,000	21,446	111,151
2012	3,491	29,020	33,906	23,541	21,719	111,677
2013	3,502	29,365	34,080	23,092	22,000	112,039
2014	3,525	29,750	34,309	22,932	22,208	112,724
2015	3,559	30,115	34,483	22,622	22,448	113,227
2016	3,578	30,415	34,809	22,655	22,612	114,069
2017	3,598	30,695	35,103	22,538	23,129	115,063
2018	3,620	30,960	35,450	22,497	23,322	115,849

NPCC 2009 Long-Term Reliability Assessment Summary- Projected "Total Internal Demand" (Winter)						
Study Year	Maritimes	New England	New York	Ontario	Québec	NPCC Total
2008 Actual	22,983	22,130	25,021	22,983	37,230	130,347
2009	22,886	22,100	24,998	22,886	36,250	129,120
2010	22,785	22,105	24,971	22,785	37,103	129,749
2011	22,443	22,175	25,020	22,443	37,576	129,657
2012	22,081	22,290	25,094	22,081	38,063	129,609
2013	21,575	22,335	25,285	21,575	38,422	129,192
2014	21,442	22,440	25,414	21,442	38,837	129,575
2015	20,840	22,540	25,517	20,840	39,121	128,858
2016	21,095	22,645	25,687	21,095	40,016	130,538
2017	21,235	22,750	25,859	21,235	40,350	131,429
2018	20,845	22,860	26,038	20,845	40,656	131,244

NPCC 2009 Long-Term Reliability Assessment Summary-Projected "Net Energy"						
Study Year	Maritimes	New England	New York	Ontario	Québec	NPCC Total
2008 Actual	28,718	131,749	165,613	148,676	188,799	663,555
2009	28,741	131,315	164,568	143,334	186,617	654,575
2010	28,545	131,330	164,423	142,724	187,479	654,501
2011	28,268	132,350	165,263	142,516	190,627	659,024
2012	28,619	134,015	166,221	141,637	193,720	664,212
2013	28,760	134,635	166,711	139,796	195,366	665,268
2014	28,982	136,085	167,773	138,327	197,206	668,373
2015	29,201	137,540	168,690	136,722	199,200	671,353
2016	29,391	139,025	170,124	136,478	203,873	678,891
2017	29,607	140,565	171,477	135,369	207,520	684,538
2018	29,827	142,125	172,939	134,608	209,155	688,654

The total average annual growth within NPCC is 0.6 percent for summer peak demand, 0.1 percent for winter peak demand, and 0.4 percent for energy.

NPCC Resource Adequacy Assessment Process

Each NPCC Area meets the NPCC resource adequacy criterion and review process as described below with the exception of Québec; beginning with the 2016–2017 winter period, additional resources must be procured.

The Northeast Power Coordinating Council, Inc. has in place a comprehensive resource assessment program directed through NPCC Document B-08, "Guidelines for Area Review of Resource Adequacy."[179] This document charges the NPCC Task Force on Coordination of Planning (TFCP) to assess periodic reviews of resource adequacy for the five NPCC areas, or subregions, defined by the following footprints:

- The Maritimes 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 (ISO New England Inc.);
- New York (New York ISO);
- Ontario (Independent Electricity System Operator); and
- Québec (Hydro-Québec TransÉnergie).

In assessing each review, the TFCP will ensure that the proposed resources of each NPCC area will comply with NPCC Document A-02, "Basic Criteria for Design and Operation of

[179] http://www.npcc.org/documents/regStandards/Guide.aspx

Interconnected Power Systems."[180] 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 load relief from available operating procedures.

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 and 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.

For the purposes of the area resource adequacy review, resources are defined as the sum of supply-side and demand-side contributions. Supply-side facilities may include all generation sources within an area as well as purchases from neighboring systems. Demand-side facilities may include measures for reducing and shifting load, such as conservation, load management, interruptible and dispatchable loads, and unmetered but identifiable small capacity generation.

Document B-08 requires each area resource assessment to include an evaluation and discussion 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.

[180] http://www.npcc.org/documents/regStandards/Criteria.aspx

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 judges if the outside assistance assumed by each area is reasonable.

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."[181] 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 BPS 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 BPS of the area and reference the most recently conducted Intermediate Review or Comprehensive Review.

[181] http://www.npcc.org/documents/regStandards/Guide.aspx

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 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

Coordinated Operations

Reliable operations within NPCC are directed through the five Reliability Coordinators of NPCC. Each of the NPCC areas also serves as a NERC Reliability Coordinator for its respective footprint as follows:

Entity Serving as NERC Reliability Coordinator	Reliability Coordinator Footprint
New Brunswick System Operator (NBSO)	Provinces of New Brunswick, Nova Scotia and Prince Edward Island; the Northern Maine Independent System Administrator, Inc.
ISO New England Inc.	States of Maine, Massachusetts, Vermont, New Hampshire, Connecticut, Rhode Island
New York ISO	State of New York
Independent Electricity System Operator (IESO)	Province of Ontario
Hydro-Québec TransÉnergie	Province of Québec

Within each area, the respective Reliability Coordinator assumes the authority and responsibility to immediately direct the re-dispatch of generation, the reconfiguration of transmission, or, if necessary to return the system to a secure state, the shedding of firm load. Coordination in the daily operation of the BPS is assisted through enhanced communications and heightened awareness of system conditions and mutual assistance during an emergency or a potentially evolving emergency. The Reliability Coordinators of the five NPCC areas conduct conference calls daily and weekly to identify and assess emerging system conditions and procedures are in place to initiate emergency conference calls whenever one or more areas anticipates a shortfall of capacity, or anticipates the implementation of operating measures in response to a system emergency.

The NERC Standards, together with the Regional Criteria's Guidelines and Procedures, establish the fundamental principles of interconnected operations among the NPCC area.

NPCC Document A-03, "Emergency Operation Criteria,"[182] presents the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination among the areas. The Criterion establishes seven basic objectives in formulating plans related to emergency operating conditions, including the avoidance of interruption of service to firm load, minimizing the occurrence of system disturbances, containing any system disturbance and limiting its effects to the area initially impacted, minimizing the effects of any system disturbances on the customer, avoiding damage to system elements, avoiding potential hazard to the public and ensuring area readiness to restore its system in the event of a major or partial blackout.

NPCC Document A-06, "Operating Reserve Criteria,"[183] defines the necessary operating capacity required to meet forecast load, to accommodate load forecasting error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie-line power flow. The NPCC "Operating Reserve Criteria" require two components of operating reserve. The ten-minute operating reserve available to each area shall at least equal its most severe first contingency loss. The thirty-minute operating reserve available to each area shall at least equal one-half its most severe second contingency loss.

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 BPS 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

[182] http://www.npcc.org/documents/regStandards/Criteria.aspx
[183] http://www.npcc.org/documents/regStandards/Criteria.aspx

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 BPS. Full membership shall be available to entities, which are general members that also participate in electricity markets in the international, interconnected BPS 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 50 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.[184]

NPCC Subregions

Maritime Area

The footprint of the Maritimes area is comprised of the provinces of New Brunswick (served by the New Brunswick System Operator), Nova Scotia (served by Nova Scotia Power Inc.), Prince Edward Island (served by the Maritime Electric Company Ltd.) and the Northern Maine Independent System Administrator, Inc (NMISA). The NMISA serves approximately 40,000 customers in northern Maine and is radically connected to the New Brunswick power system. The Maritimes Area is a winter-peaking subregion.

On October 1, 2004, New Brunswick's Electricity Act restructured the electric utility industry in New Brunswick and created the New Brunswick System Operator (NBSO). It is an independent not-for-profit statutory corporation separate from the NB Power group of companies. The Electricity Act transferred the responsibility for the security and reliability of the integrated New Brunswick electricity system from NB Power to NBSO, and also made NBSO responsible for facilitating the development and operation of the New Brunswick Electricity Market. These responsibilities take the form of operation of the NBSO-controlled grid and administration of the NBSO Open Access Transmission Tariff (OATT), and the New Brunswick Market Rules. On February 1, 2007, the Nova Scotia Electricity Act came into effect, enabling wholesale market access with the implementation of the Nova Scotia Market Rules. The Nova Scotia Power System Operator (NSPSO) is that function of NSPI that is responsible for the reliable operation of the integrated power system in Nova Scotia, as well as administration of the NS Market Rules and the Nova Scotia OATT, which has been in effect since November 1, 2005.

By contractual agreement, the NBSO acts as the Reliability Coordinator for the Maritimes Area.

The forecasting method for each reporting entity is summarized as follows:

---

[184] http://www.npcc.org

The **NBSO** load forecast for New Brunswick is based on 30-year average temperatures (1971–2000) with the annual peak hour demand determined for a design temperature of -24°C over a sustained 8-hour period. It is prepared based on a cause and effect analysis of past loads, combined with data gathered through customer surveys, and an assessment of economic, demographic, technological, and other factors that affect the utilization of electrical energy.

The **NSPI** load forecast for Nova Scotia is based on the ten-year average temperatures measured in the Halifax Area of the province, 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.

The **MECL** load forecast for PEI uses an econometric model that factors in the historical relationship between electricity use and economic factors such as gross domestic product, electricity prices, and personal disposable income.

The **NMISA** load forecast for northern Maine is based on historic average peak-hour demand patterns inflated at a nominal rate and normalized to 30-year average historical weather patterns. Economic and other factors may also affect the forecast.

The 2009 to 2010 peak demand forecast, representing the summation of the forecasts of each Maritimes Area jurisdiction, is 5,554 MW. This is 308 MW lower than the value forecast for the 2008 assessment. The forecast average annual peak demand growth rate is 0.4 percent over the next 10 years, and this is lower than the 0.9 percent growth rate forecast last year. Contributing significantly to this lower forecast are announced mill closures in the pulp, paper, and wood processing sectors, along with limited growth expectations in these sectors, and lower growth projections for the gross domestic product.

Separate demand and energy forecasts are prepared by each of the Maritimes Area jurisdictions, as there is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. For area studies, the individual forecasts are combined using the load shape of each jurisdiction. 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 Operator). For the actual peak demand it is the total hourly coincident peak done on a weekly bases of each sub-area.

All jurisdictions in the Maritimes Area are winter peaking due to high electric heating load. Long term resource evaluations are based on a 20 percent Reserve Margin above the forecast firm winter peak load.

Current and projected energy efficiency programs are either incorporated directly into the load forecast (New Brunswick and Northern Maine), or reported separately (Nova Scotia and PEI). The reported energy efficiency for 2009–2010 is 25 MW (NS and PEI combined), and is partly due to provincial and federal programs for home renovations.

Nova Scotia Power Inc.'s energy efficiency programs are spread across various customer sectors, residential, commercial, and industrial. They include programs for lighting, heating and cooling, refrigeration, water heating, motors, and compressors. NSPI has developed an updated DSM plan which is presently before the Regulator. DSM is a relatively new initiative for NPSI and the program includes reporting mechanisms (independent evaluation by NSPI's Evaluation Consultant, and subsequent verification by the Regulator's Verification Consultant) to assess the demand and energy benefits, particularly during the ramp-up period in the next few years.

One of the Demand Response programs currently utilized in the Maritimes Area is interruptible demand. For 2009 to 2010, the interruptible demand forecast for the peak month is 441 MW, which represents 7.9 percent of the peak demand forecast. In Nova Scotia, NSPI's Demand Response programs are primarily rate design-driven and along with interruptible pricing for large industrials, include time of day pricing for residential customers with electric thermal storage home heating equipment, and the Extra Large Industrial Interruptible Two Part Real Time Pricing rate for NSPI's two largest customers. Interruptible demand is reported separately; the other programs are incorporated directly into the load forecast.

In its comprehensive reviews of resource adequacy, the Maritimes Area uses a load forecast uncertainty representing the historical standard deviation of load forecast errors based upon the four year lead time required to add new resources.

The Maritimes Area capacity resources in 2009 to 2010 and 2018 to 2019, with wind capacity in brackets, are:

	2009/10	2018/19
Existing Certain	6,318 MW (105 MW)	6,266 (105 MW)
Existing Other	251 MW (244 MW)	251 MW (244 MW)
Existing Inoperable	20 MW (0 MW)	20 MW (0 MW)
Future	897 MW (239 MW)	1238 MW (580 MW)
Conceptual	0 MW (0 MW)	0 MW (0 MW)

Wind project capacity for the Maritimes is modeled based upon results from the September 21, 2005 NBSO report "Maritimes Wind Integration Study."[185] This report showed the effective capacity from wind projects, and their contribution to Loss of Load Expectation, was equal to or better than their seasonal capacity factors. The effective capacity for wind generation is derived from the historical three-year seasonal average output. Expected winter capacity over the study period is 105 MW; expected summer capacity over the study period is 61 MW. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

In Nova Scotia, the capacity contribution of wind projects during the peak is based on a three-year rolling average of the winter peak period actual capacity factor (combined with the annual forecasted capacity factor, if in service less than three years). This is based on an agreed formula between the Renewable Energy Industry Association of Nova Scotia and NSPI.

Biomass capacity values are 137 MW of Existing Certain and 5 MW of Existing Other in both 2009–2010 and 2018–2019.

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

Planned and Proposed capacity resources are based upon the most recent 10-year projections submitted to NBSO by the load serving utilities in the Maritimes Area. Planned resources are required to be in construction. Proposed resources include known project announcements and legislated renewable energy requirements for utilities.

The Maritimes Area does not forecast any capacity imports from other Regions during the next 10 years.

For the period 2009 through October 2011, there is a firm capacity sale of 200 MW from the Maritimes to Hydro-Québec. This sale is tied to two 100 MW Oil CT's at Millbank, New Brunswick. This sale is also backed up by a transmission reservation.

As defined by NERC, the following transmission projects are being considered or are in progress:

- Conceptual — New Brunswick is actively studying a 345 kV transmission line between Coleson Cove and Salisbury, a line which would be 103 miles in length, and targeted for completion in 2016. The project is being developed to meet specific energy projects still in the conceptual stages, and its delay will not currently impact the reliability of BPS.

- Planned — Nova Scotia is planning a 138 kV transmission line project near Canaan Rd. This line is 27 miles in length, and targeted for completion in 2010.

- Under Construction — PEI is building a 138 kV transmission line project from Sherbrooke to West Cape. This line is 51 miles in length, and targeted for completion in 2009.

The Maritimes Area has no current transmission constraints significantly affecting reliability.

Transmission Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
Coleson Cove, NB 345 kV to Salisbury	345	103	2016	Conceptual
Canaan Rd, NS 138 kV line	138	27	2010	Planned
Sherbrooke, PEI 138 kV to West Cape	138	51	2009	Under Construction

No significant transformer additions or other significant substation equipment are planned for the Maritimes Area within the next 10 years. There are no significant anticipated generating unit outages, transmission additions, or temporary operating measures that are anticipated to impact the reliability of the Maritimes during the next ten years.

In its 2007 Maritimes Comprehensive Review of Resource Adequacy http://www.npcc.org/documents/reviews/Resource.aspx, scenarios of high-load growth and zero-wind availability were studied, with the result that the Maritimes Area was still able to meet its 20 percent reserve criterion in all cases with no more than 35 MW of necessary interconnection support. This level of interconnection support represents only 2.1 percent of the Maritimes Area tie benefits capability.

There are no current environmental or regulatory restrictions that could potentially impact the reliability of the Maritimes Area.

Plans are underway for the individual jurisdictions within the Maritimes Area to coordinate the sharing of wind data and possibly wind forecasting information and services.

In Nova Scotia, Provincial legislation is in place to meet renewable supply targets in 2010 and 2013 (including variable and intermittent resources). The 2008 Wind Integration Study commissioned by the Nova Scotia Department of Energy[186] found that for the 2013 target, more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure. Future study will be needed to fully understand the cost and stability issues of increasing wind supply beyond these levels.

There are no operational changes or concerns resulting from distributed resource integration in the Maritimes Area other than in Nova Scotia. In Nova Scotia, as increased amounts of renewable generation are connected to the distribution system, further study will be required to fully understand the cost and technical implications related to possible transmission system upgrades and new operational demands on existing infrastructure.

There are no low water level concerns or high temperature concerns for the Maritimes Area. As a significantly winter-peaking subregion, low water levels from run-of-river hydro generation are always assumed for planning, and high temperatures during summer months do not produce significant load levels.

For each year of the forecast, the Reserve Margin of the Maritimes Area exceeds 34 percent. The Maritimes uses a reserve criterion of 20 percent for planning purposes and it was shown in the 2007 Maritimes Comprehensive Review of Resource Adequacy[187] that adherence to this criterion complies with the NPCC reliability criterion.

The Maritimes conducts resource adequacy studies to identify the resources needed to meet the NPCC resource adequacy criterion of less than 0.1 days per year of Loss of Load Expectation (LOLE).

In its 2007 Maritimes Comprehensive Review of Resource Adequacy,[188] it was shown the NPCC reliability criterion of less than 0.1 days of firm load disconnections per year is not exceeded by the Maritimes Area for all years in the 2008 –2012 study period, and varies between 0.001 to 0.086 days per year for the base load forecast with load forecast uncertainty. The Maritimes Area

[186] http://www.gov.ns.ca/energy/resources/EM/Wind/NS-Wind-Integration-Study-FINAL.pdf
[187] http://www.npcc.org/documents/reviews/Resource.aspx
[188] Ibid.

requires no support from its interconnections to meet the NPCC reliability criterion for all years of the 2008–2012 study period. The Maritimes Area is also shown to adhere to its own 20 percent reserve planning criterion in all years for the base load forecast with reserve levels varying between 22 percent and 40 percent.

The Maritimes Area has sufficient resources to meet its 20 percent reserve requirement for each of the 10 years of this assessment. No additional internal or external resources are required.

The Maritimes Area participates in a Regional reserve sharing program with New England, New York, and Ontario for 100 MW of 10-minute reserve. This reserve is counted as 25 percent spinning and 75 percent supplemental.

Both short-term and long-term capacity requirements are the same in the Maritimes Area.

The most significant change since the last assessment is a lower demand forecast and demand growth rate for the Maritimes. Contributing significantly to this lower forecast are announced mill closures in the pulp, paper, and wood processing sectors, along with limited growth expectations in these sectors. With this lower demand, comes higher forecast Reserve Margin, therefore less need to plan for any major new capacity in the Maritimes.

In its 2007 Maritimes Comprehensive Review of Resource Adequacy[189], scenarios of high-load growth and zero-wind availability were studied, with the result that the Maritimes Area was still able to meet its 20 percent reserve criterion in all cases with no more than 35 MW of necessary interconnection support. This level of interconnection support represents only 2.1 percent of the Maritimes Area tie benefits capability.

Wind project capacity for the Maritimes is modeled based upon results from the September 21, 2005 NBSO report "Maritimes Wind Integration Study."[190] This report showed that the effective capacity from wind projects, and their contribution to LOLE, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer-peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

In Nova Scotia, the capacity contribution of wind projects during the peak is based on a three-year rolling average of the winter peak period actual capacity factor (combined with the annual forecasted capacity factor, if in service less than three years). This is based on an agreed formula between the Renewable Energy Industry Association of Nova Scotia and NSPI. Wind capacity required to meet Maritimes Area RPS mandates has been included within Future Capacity.

All generation projects connecting to the transmission grid, including wind, must undergo a System Impact Study (SIS) and satisfy all connection requirements determined by the SIS and

[189] Ibid.
[190] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_ Final_.pdf

local grid code. Wind projects are required to transmit atmospheric data (wind speed, wind direction, temperature) to the local System Operator for wind forecasting needs. Also, see 5(d).

One of the Demand Response programs considered in Maritimes Area resource assessments is interruptible load.

There are no unit retirements in this assessment that significantly impact the reliability of the Maritimes Area.

Generation deliverability for the Maritimes is addressed through a combination of resource adequacy and transmission reliability studies. Resource adequacy studies use multi-area probabilistic analysis in order to verify that intra-area constraints do not compromise resource adequacy. Comprehensive transmission studies are performed for sub-areas to ensure generation is sufficiently integrated with load.

The 658 MW Point Lepreau nuclear station in New Brunswick is currently undergoing a scheduled 18-month refurbishment, with a planned return to service date of October 2009. This refurbishment project is now forecast to be six-months behind schedule, and its return to service delayed until the first quarter of 2010. Capacity purchases may be arranged to mitigate the extended outage of Point Lepreau, similar to the 2008–2009 winter when the purchase of 200 MW was made from Québec to New Brunswick.

In Maritimes Area assessments, external sources are only considered available if there is a firm contract.

At this time, there are no plans to install more UVLS in the Maritimes Area.

The Maritimes Area addresses the loss of generation through its operating reserve requirements. Due to its diverse fuel mix and fuel storage, no long-term fuel disruptions are anticipated.

The Maritimes area has experienced above-average levels of hydro power the last few years. Low run-of-river hydro is planned for and expected during winter peak loads. Nuclear capacity will be increased by 100 MW due to the refurbishment of Point Lepreau.

The Maritimes area does not have guidelines for on-site spare GSU and autotransformers.

NPCC has established a Reliability Assessment Program to bring together work done by the Council, its member systems, and areas relevant to the assessment of BPS reliability. As part of the Reliability Assessment Program, TFSS is charged on an ongoing basis with conducting periodic reviews of the reliability of the planned bulk power transmission system of each area of NPCC and the transmission interconnections to other areas. The purpose of these reviews is to determine whether each area's planned bulk power transmission system is in conformance with the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems*.[191] Since the *Basic Criteria* are at least consistent with, or exceed, the NERC *Planning Standards*,

[191] NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2). (Document A-2)

conformance with the NPCC *Basic Criteria* assures consistency with the NERC *Planning Standards*. To meet these requirements, the Transmission Review conducted in 2008 was an Intermediate Review, covering the study year of 2013. The results of this study included the following:

Pre-disturbance Steady State Assessment of the 2013 System

The base cases indicate that under all loading and import and export conditions:

- all line and equipment loading are within normal limits,
- all voltages in the system are within normal limits ($0.95<V<1.05$), and
- there is enough dynamic reactive power capacity with adequate reserve in addition to other facilities such as shunt capacitors and reactors for voltage and var control under all load levels.

Normal Contingency Analysis

The analysis of the Normal Contingency simulations indicated stable system performance and satisfactory post contingency voltage and thermal conditions in all cases.

Extreme Contingency Analysis

The analysis of the Extreme Contingency simulations indicated they did not have any adverse impact on neighbouring systems.

Further, the analysis of the simulations completed in this review indicated that planned wind projects did not result in any unacceptable voltage or equipment loading or any adverse impact on the stability of the BPS. None of the studied contingencies resulted in any of the wind generators tripping or experiencing unacceptable oscillations.

No new FACTS or "Smart Grid" devices are planned for the Maritimes Area BPS during the assessment period. There are no known reliability impacts due to aging infrastructure in the Maritimes Area. There are no known reliability impacts due to economic conditions in the Maritimes Area. There are no other issues unique to the Maritimes Area that will impact reliability over the ten-year study period.

Description of the Maritimes Subarea

The following entities physically comprise the NPCC subarea defined as the Maritimes Area:

Jurisdiction	System Operator	Peak Season	Square Miles	Population
New Brunswick	NBSO	Winter	28,000	750,000
Nova Scotia	NS Power	Winter	21,000	940,000
Prince Edward Island	Maritime Electric	Winter	2,200	140,000
Northern Maine	Northern Maine Independent System Administrator, Inc. (NMISA)	Winter	3,600	90,000

New England Subregion

For this *2009 Long-Term Reliability Assessment*, ISO New England Inc. (ISO-NE) forecasts no major reliability issues with respect to fuel supply, availability of both supply or demand-side resources, or the capability of the Regional transmission system to serve the projected seasonal peak loads and energy requirements of the six states New England Region.

The summer Reserve Margins for existing certain and net firm transactions range from a high of 25.5 percent in 2011 to a low of 7.1 percent in 2018. While accounting for new prospective capacity resources, the summer Reserve Margins increase to a high of 30.9 percent in 2011 and to a low of 12.1 percent in 2018. The winter Reserve Margins for existing certain and net firm transactions range from a high of 63.8 percent in the winter of 2009/2010 to a low of 43.7 percent in the winter of 2010/2011. The winter Reserve Margins are higher because the winter-peak load is lower than that of the summer-peak load. Accounting for new prospective capacity resources, the winter Reserve Margins increase to a high of 67.7 percent in the winter of 2009/2010 and to a low of 47.0 percent in the winter of 2010/2011.

Beginning with this year's NERC *Long-Term Reliability Assessment* submittal, a 20 percent Confidence Factor has been applied to the amount of projected Conceptual Capacity Resources. This 20 percent Confidence Factor represents the amount of Conceptual Capacity that may become commercialized within the Region, starting in the year 2010. This 20 percent Confidence Factor is held constant going forward in time. In the summer of 2018, this equates to approximately 2,492 MW.

This 20 percent value for the Confidence of Conceptual Resources was developed from a historical trend that reflects the amount of capacity that has commercialized from within ISO-NE's Generator Interconnection Queue. ISO-NE's Conceptual Capacity reflects all the remaining capacity within the ISO-NE Generator Interconnection Queue that has not been classified as either Future, Planned or Future, Other-Capacity Additions. The summer Reserve Margins for Adjusted Potential Resources range from a high of 34.6 percent in 2011 to a low of 19.2 percent in 2010. The winter Reserve Margins for Adjusted Potential Resources range from a high of 70.4 percent in the winter of 2015/2016 to a low of 50.4 percent in the winter of 2010/2011. The amount of future Conceptual Capacity that does become commercial will depend on market need. ISO-NE's Forward Capacity Market (FCM) will ensure the procurement of Regional capacity to maintain forward-going resource adequacy. Maintaining the delivery of both internal and external capacity in the near-term (0–4 years out) is a significant factor in regards to ensuring that the projected Reserve Margins are met.

Open Issues

This *2009 Long-Term Reliability Assessment* identifies three issues going forward that could possibly impact system reliability. These three issues are the potential impact on system operations and Regional capacity (and thus, resource adequacy) from:

- A potentially large influx in the amount of new, intermittent capacity resources like wind generation.192 Currently, New England has very little existing wind capacity (less than 100 MW of nameplate), but concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the corresponding build-out of these new supply-side resources in the near-term. Because of this and other operational concerns, ISO-NE is currently embarking on a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid. This wind study will also propose solutions to those problems.
- The unknowns associated with upcoming nuclear plant relicensing that is scheduled to occur within a 3–16 year time frame,193 and
- The potential need to modify, refurbish, or retire both river and coastal steam-generation power plants that currently use "once-through" cooling with "closed-loop" cooling systems. Current rulemaking at the U.S. EPA, which has been recently ruled on by the U.S. Supreme Court, injects uncertainty into the process for which revised NPDES194 water permits may soon mandate cooling tower arrangements in order to reduce the impact on aquatic life due to power plant cooling operations.

The first issue is an emerging operational issue. The last two issues can be combined and categorized as a potential loss of operable capacity, with that potential loss being either temporary or permanent in nature. The reliability impacts stemming from the last two issues equate to a resource adequacy issue.

Demand

ISO-NE's reference case load forecast is a 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted temperature-humidity index (WTHI) of 80.1, which is equivalent to a dry-bulb temperature of 90.4 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The reference case load forecast is based on the most recent reference economic forecast, which reflects the economic conditions that "most likely" would occur.

The current economic conditions have lowered this year's forecast for peak load and energy when compared to last year's (2008). However, this year's forecast of the summer peaks' ten-year compound annual average growth rate has stayed the same as last year's forecast, holding at 1.2 percent. However, this 2009 compounded annual growth rate is somewhat misleading, as the load level in the first year (2009) of the forecast is significantly lower due to the current economic recession. This biases the overall compounded annual average growth rate in an upward fashion. This upward bias is also true for the corresponding ten-year compound annual growth rate for the Region's annual energy forecast.

[192] Currently, ISO-NE has approximately 2,500 MW (total) of new onshore and offshore wind projects requesting study within its Generation Interconnection Queue.

[193] Within New England, approximately 1,300 MW of nuclear capacity has their current NRC Operating License expiring within a three-year timeframe and approximately 3,350 MW of nuclear capacity has their current NRC Operating License expiring within a 16-year timeframe.

[194] The National Pollutant Discharge Elimination System (NPDES).

This year's forecast for the winter peaks' ten-year compound annual average growth rate has been significantly reduced from last year's forecast of 0.9 percent down to 0.4 percent as a result of recent changes in the forecast method. The change in forecast method reflects the elimination of the growth trend on the weather sensitive portion of the winter-peak load. This method change subsequently results in even lower winter peak forecasts when compared with the 2008 long-term forecast.

This year's forecast of the net annual energy's ten-year compound annual average growth rate has been modestly increased from last year's forecast of 0.8 percent up to 0.9 percent. However, this 2009 compound annual growth rate is also somewhat misleading, as the energy levels in the first year (2009) of the forecast are significantly lower due to the current economic recession. This biases the overall compounded annual average growth rate in an upward fashion. The overall forecast for energy is lower on an annual basis. The key factor leading to the lower forecasts is that the current economic recession has significantly impacted the actual peak loads and energy demand within the New England Region, which results in approximately a one to two year delay in achieving the same demand levels that had been previously predicted in the 2008 forecast.

ISO-NE develops an independent load forecast for the Balancing Authority Area as a whole and the six states within it. ISO-NE uses historical hourly load data on individual member utilities, which is based upon Revenue Quality Metering (RQM),[195] to develop historical load data from which the Regional peak load and energy forecasts are based. From this, ISO-NE develops a forecast of both state and monthly peak loads and energy demand. The peak load forecast for the Region and the states can be considered a coincident peak load forecast.

It is anticipated that 2,420 MW of demand resources will be available by August 2009. These include resources in ISO-NE's Real-Time 30-Minute (1,710 MW), Real-Time 2-Hour (186 MW), and Profiled Demand Response (18 MW) programs, which could be instructed to interrupt their use during specific actions of ISO-NE Operating Procedure No. 4 — *Action during a Capacity Deficiency* (OP4).[196] Some of the assets in the Real-Time Demand Response programs are under direct control. The direct load control involves the interruption of central air conditioning systems in residential, commercial, and industrial facilities. Also included in the total is 506 MW of energy efficiency.

The 2,420 MW of demand resources is expected to grow to 2,937 MW by 2011 because that is the amount of demand resources that has cleared ISO-NE's Forward Capacity Auction (FCA) for the 2011–2012 commitment period.[197,198] That amount subsequently decreases to 2,530 MW by the summer of 2012,199 and is held constant through 2018.

---

195 RQM is submitted to the ISO-NE Settlement Department.

196 ISO-NE Operating Procedure No. 4 can be found on the ISO-NE web site located at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html

197 This value includes passive Demand Response resources at 983 MW or 33 percent and active-demand resources at 1,954 MW or 67 percent, as indicated in the draft version of RSP09.

198 Commitment periods within New England's FCM represent the forward timeframe from June 1 to May 31.

199 Beginning in the summer of 2010, Demand Response values are based on demand resources with obligations within ISO-NE FCM. In addition to the 8 percent transmission and distribution loss gross-up, the 2010 and 2011 summers' totals include Reserve Margin gross-ups of 14.3 percent and 16.1 percent respectively. Due to

Energy efficiency programs are considered capacity resources in New England's FCM. Under FCM, energy efficiency can be included in the category of on-peak demand resources,[200] which includes installed measures (e.g., products, equipment, systems, services, practices, and 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. As part of the qualification process to participate in an FCA, any new demand resource must submit detailed information about the project, including location, project description, estimated demand reduction values, and expected commercial operation dates along with a project completion schedule. In addition, new demand resources must submit a Measurement and Verification (M&V) Plan, which must be approved by ISO-NE. The project sponsor is required to submit certification that the project complies with their ISO-approved M&V Plan. ISO-NE has the right to audit the records, data, and actual installations to ensure that the energy efficiency projects are providing the load reduction as contracted. ISO-NE tracks the project against their submitted schedules, thereby taking a proactive role in monitoring the progress of these resources to ensure they are ready to reduce demand by the start of the applicable FCM commitment period.

In addition to reliability-based programs, ISO-NE administers a price-response program where load voluntarily interrupts based on the price of energy. As of April 24, 2009 there were approximately 81 MW enrolled in the price response program. These programs are not counted as capacity resources since their interruption is voluntary.

ISO-NE addresses peak demand uncertainty in two ways:

- Weather — Annual peak load distribution forecasts are made based on 38 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded);[201]
- Economics — Alternative forecasts are made using high and low economic scenarios.

ISO-NE also reviews projected summer and winter conditions of the study period using the annual extreme, 90/10 peak demand based on the reference economic forecast.

Generation

ISO-NE's deliverable capacity resources amount to 33,703 MW in 2009.[202] That includes 33,417 MW of Existing Certain generating capacity (which includes 2,420 MW of Demand Response resources), 58 MW of net firm imports and exports, and 228 MW of planned generating capacity, which is expected to become commercial by summer 2009. The total new

recent changes in FCM market rules; these gross-ups will no longer be applied after the 2011–2012 commitment period, so the demand resource numbers decrease to 2,530 MW.

[200] The rules addressing the treatment of demand resources in the FCM may be found in Section III.13.1.4 of ISO-NE's *Market Rule 1, Standard Market Design*, located at http://www.iso-ne.com/regulatory/tariff/sect_3/v8-7-1-08_mr1_sect_13-14.pdf.

[201] On an annual basis, the 50/50 reference peak has a 50 percent chance of being exceeded, and the 90/10 extreme peak has a 10 percent chance of being exceeded.

[202] Due to differences in assumptions, the amount of existing and planned capacity in summer 2009 is different from that published in ISO-NE's 2009 to 2018 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report).

generation expected to be in service by August 2011 amounts to 1,349 MW. In addition to the planned capacity, ISO-NE has a total of 12,462 MW of conceptual (capacity) projects in its Generator Interconnection Queue,[203] with in-service dates ranging from 2009 to 2015. Although some projects that reside within the ISO-NE Generator Interconnection Queue have declared in service dates of 2009 or 2010, some of those projects have not demonstrated viable pre-commercial activities and have therefore been categorized as conceptual capacity.

As noted earlier, a 20 percent Confidence Factor has been applied to the amount of projected Conceptual Capacity Resources. This 20 percent Confidence Factor represents the amount of Conceptual Capacity that may become commercialized within the Region, starting in the year 2010. This 20 percent Confidence Factor is held constant going forward in time. In the summer of 2018, this equates to approximately 2,492 MW.

Approximately 39 MW of the existing certain capacity is wind generation expected during the peak season for the summer of 2009. The total nameplate capability of those wind facilities is approximately 100 MW. Planned capacity includes 88 MW (350 MW nameplate) of new wind capacity. Planned wind capacity is rated different from its nameplate capability due to market rules for rating intermittent supply-side resources, which also takes into account the site-specific wind characteristics of those projects. Conceptual wind capacity in New England amounts to 2,180 MW based on nameplate ratings, which has target in-service dates of 2009 through 2014.

Also included in the existing certain capacity are 1,694 MW of variable hydro resources expected on peak.

Biomass capacity in the existing certain category totals 916 MW. A total of 468 MW of conceptual biomass capacity is proposed for installation in New England with target in-service dates of 2009 through 2014.

ISO-NE's Reserve Margin calculations include future capacity resources that are expected to begin commercial operation by the end of 2009. If the new project's 2009 in-service date is prior to August 1, 2009, that capacity is included within the future planned capacity for the summer 2009, otherwise it is included within the future planned capacity for the winter 2009/2010. This information is based on either the date specified in a signed Interconnection Agreement or discussions with ISO-NE indicating the project is nearing completion and is preparing to become an ISO generator asset. Also included in the future capacity resources are new projects that have contractual obligations within the ISO-NE FCM for the years 2011–2012. Conceptual capacity is subsequently identified as all the capacity remaining within the ISO-NE Generation Interconnection Queue that has not been designated as future planned capacity, within the NERC *2009 Long-Term Reliability Assessment*, through the selection process identified above.

Capacity Transactions on Peak

Firm summer imports amount to approximately 401 MW in 2009, 899 MW in 2010, and 2,298 MW for 2011 and 2012. The imports for 2010 and 2011 reflect the FCA results. The 2011 FCA results were assumed to remain in place in 2012. Since the FCA imports are based on one-year contracts, beginning in 2013 the imports reflect only known, long-term Installed Capacity

[203] As of the March 15, 2009 ISO-NE Generation Interconnection Queue publication.

(ICAP) contracts. Firm summer imports decrease to 334 MW in 2013 and 2014, and decrease again to 284 MW in 2015 and 112 MW in 2016, and then level off at 6 MW for the summers of 2017 and 2018. If the imports that cleared in summer 2011 and 2012 do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or demand-side resources.

A total of 2,298 MW of import capacity resources cleared in the second FCA for the 2011–2012 commitment period. Import capacity is subject to prorating if its supply offers exceed the capacity transfer limit of the external transmission interface. Three external interfaces had excess supply offers at the conclusion of the auction. The Hydro-Québec Highgate external interface had 14 MW of excess supply offered above its capacity transfer limit of 200 MW. The New York AC Ties external interface had 138 MW of excess supply offered above its capacity transfer limit of 1,352 MW. The New Brunswick external interface had 16 MW of excess supply offered above its capacity transfer limit of 284 MW. All of this excess import capacity (MW) offered at these three external interfaces were subsequently prorated down to match the import capacity transfer limit of each of the external transmission interfaces.

The entire amount of ICAP imports are backed by firm contracts for generation and the imports under the FCM are import capacity resources with an obligation for the 2010–2011 and 2011–2012 commitment periods. Although there is no requirement for those imports to have firm transmission service, it is specified that deliverability of firm imports must meet New England delivery requirements 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 firm energy, but the market participant bears the associated risk of market penalties if it chooses to use non-firm transmission services.

For the summer of 2009, ISO-NE reports a firm capacity sale to New York (Long Island) of 343 MW, anticipated to be delivered via the Cross Sound Cable (CSC). This sale will be reduced to 100 MW beginning in 2010. It should be noted that there is no firm transmission arrangement through the New England PTF system associated with this contract.

Transmission

ISO-NE's Regional System Plans (RSPs)[204] identify the Region's needed transmission improvements for this ten-year period. Each RSP describes the transmission upgrades that are critical for maintaining the bulk transmission system. The New England Region currently has over 200 transmission projects and components[205] in various stages of planning, construction, and implementation. Presently there are no significant concerns over meeting target in-service dates. However, if the implementation of much needed projects is delayed, interim measures will be taken, such as issuing gap *Requests-for-Proposals* (RFPs) to install temporary generation in a specific area of the system.

Currently, there are no transmission constraints that would significantly impact Regional reliability. However, there are localized system concerns where the system is highly dependent

[204] Summaries of transmission studies and projects can be found in the ISO-NE 2009 Regional System Plan (final report expected to be posted by the end of 2009) at www.iso-ne.com/trans/rsp/index.html

[205] The project listing can be found on the ISO-NE web site at www.iso-ne.com/trans/rsp/index.html

upon the operation of available generation. Special operating measures may have to be employed if this generation becomes 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 citing review.

Operational Issues

There are no significant anticipated generating unit outages, transmission outages or temporary operating measures that are anticipated to impact reliability during the next ten years. A potentially large influx in the amount of new, intermittent capacity resources, such as wind generation, could commercialize in the near-tem.[206] Nuclear plant relicensing[207] and replacement of *once-through* cooling systems[208] are probably the only major open issues. Planned outages and the addition of new facilities is coordinated by ISO-NE and must pass through a rigorous operational review to ensure continued system reliability before allowing such system outages or enhancements to occur. The Regional natural gas industry has also begun to coordinate their expansion and maintenance requirements with ISO-NE. Coordinating maintenance between the gas and electric industries works to ensure both natural gas and electric system reliability, when scheduling planned outages for pipelines, LDCs, electric generation, and bulk transmission.

If New England experiences extreme summer weather that results in 90/10 peak loads or greater, ISO-NE still should have enough operable capacity available to reliably manage the BPS. However, if supply-side outages diminish New England's operable capacity to serve these 90/10 peak loads, ISO-NE will need to invoke Operating Procedure No. 4 — *Action During a Capacity Deficiency* (OP4). OP4 is designed to provide the additional generation and load relief needed to balance electric supply and demand while striving to maintain appropriate levels of operating reserves. Load relief available under OP4 includes relief from voltage reduction and emergency assistance from neighboring balancing authorities.[209]

---

[206] Currently, ISO-NE has approximately 2,500 MW of new wind (onshore and offshore) projects requesting study within its Generation Interconnection Queue.

[207] Approximately 1,300 MW of nuclear capacity has their NRC Operating License expiring within three years and approximately 3,350 MW of nuclear capacity has their NRC Operating License expiring within 16 years. It is unknown at this time whether the owners of these nuclear assets will apply to the NRC for an extension to their current operating permits.

[208] Clean Water Act Section 316b (dealing with intake requirements) requires a significant reduction of the impacts of impingement and entrainment of aquatic organisms in existing power plants. The reduction measures must reflect the use of Best Available Technology (BAT). The BAT requirements are implemented when the existing National Pollution Discharge Elimination System (NPDES) permits for power plants expire and subsequently are renewed. Currently, EPA provides guidance on renewal on a permit-by-permit basis. On April 1, 2009 the U.S. Supreme Court delivered an opinion that benefit/cost analyses could be used in determining the BAT permit requirements. Without considering benefit/cost, existing generating plants potentially would need to retrofit cooling towers to meet these requirements. One New England plant's recent NPDES permit renewal requires cooling towers or alternatives with an equivalent performance. It also could affect system reliability through the reduction of plant capacity and, possibly, extended construction outages of key generating facilities. The ISO will monitor the EPA's follow up regarding the Supreme Court's decision on the permitting process and the use of benefit/cost to determine whether any reliability evaluation is needed regarding the potential for retrofitting existing plants with cooling towers.

[209] It should be noted that within NPCC, there are power systems that are both summer and winter peaking. Since the New England system is summer peaking, surplus operable capacity should be available with the NPCC Canadian systems due to their winter peaking nature. This surplus operable capacity could be delivered to New England in the event OP4 is required. Routine discussions within NPCC identify whether surplus operable capacity is available on a on a daily, weekly or seasonal basis.

During extremely hot summer days combined with low hydrological conditions, there may be environmental restrictions on river-based generating units due to low water conditions or coastal generating units due to (high) water discharge temperatures. Such conditions could result in temporary operable capacity reductions ranging from 150 to 200 MW. These reductions are reflected in ISO-NE's forced outage assumptions. ISO-NE monitors these situations and projects adequate resources to cover such environmental outages or reductions.

As of the summer of 2009, there is less than 50 MW of expected on-peak wind capacity on the New England system, so operational challenges from the integration of variable resources are negligible at this time. However, in the near-term, one emerging issue is the potential for a large influx of intermittent wind resources to be commercialized within the Region. Concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the potential build-out of these new supply-side resources in the near-term. Because of this and other operational concerns, ISO-NE is currently embarking on a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid. This wind study will also propose solutions to those problems.

As discussed earlier, 2,420 MW of system demand is currently enrolled in Demand Response programs in 2009. With the start of the FCM in 2010, Demand Response, energy efficiency, and distributed generation all will be treated as capacity resources, and demand resources will represent over nine percent (2,937 MW) of the representative capacity resources needed (i.e., the Installed Capacity Requirement (ICR)) within the New England electric system by 2011.

Demand resources within FCM are categorized into two general categories: passive projects (energy efficiency) and active projects (Demand Response). Active projects are designed to reduce peaks in electric energy use and supply capacity by reducing peak load (MW). The FCM includes two types of active projects: real-time Demand Response-active, individual resources, such as active load management and distributed generation (DG) at commercial and industrial facilities and, real-time emergency generation (RTEG) — active, emergency distributed generation. Within the timeframe of 2011–2012, 2,937 MW of demand resources cleared in the FCA2.

Due to the fact that distributed generation must be integrated into the local electric company's distribution systems, it must comply with the interconnection standards applicable to such systems. This distributed generation is traditionally not a major concern for BPS operation, although relatively large DG projects can be studied by ISO-NE. A 600 MW cap on real-time emergency generation (RTEG) within FCM was a limit that was negotiated during the development of the Market Rules[210] for FCM.

To determine whether these expected levels of demand resources could be reliably integrated in New England without having a negative impact on system operations, ISO-NE has performed an

[210] RTEG is limited to 600MW in the FCA per the Market Rule III.13.2.3.3.(f) Treatment of Real-Time Emergency Generation Resources: In determining when the FCA is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation (RTEG) resources shall be counted towards meeting the ICR (net of Hydro-Quebec Interconnection Capacity Credits (HQICCs)).

initial demand resource operable capacity analysis. The analysis focused on varying levels of demand resource participation. This initial analysis showed the 2010 demand resource levels met the criteria needed for system reliability; however, the analysis of the outcome of FCA2 for the 2011/12 delivery year identified several operational issues and the potential need to change some FCM market rules. Specific concerns were as follows:

- The ability of demand resources to maintain reduction without "fatigue" during the anticipated hours of operation
- Access to the resources outside the initially approved program hours and requirements
- The appropriateness of reserve "gross-up" rules
- Auction transparency during the annual auctions
- Infrastructure and telemetering requirements for the demand resources

ISO-NE subsequently led an open stakeholder process that included a review of the operable capacity analysis and updated FCM rules regarding demand resources. This stakeholder process culminated with unanimous stakeholder support and ultimately resulted in a FERC filing on October 1, 2008, which FERC approved on October 28, 2008. The rule revisions included several provisions:

- Affecting the dispatch of Active Demand Resources[211]
- Affecting Critical-Peak Demand Resources212
- Providing better information to facilitate demand resource participation in FCA
- Clarifying ISO-NE's ability to impose appropriate sanctions in the event that market participants with demand resources do not comply with their obligations

ISO-NE's real-time operational practices are being revised to integrate large quantities of demand resources. These changes can be summarized as modifications to OP4 and operator interfaces, the creation of demand-designated entities that can aggregate the operation of demand resources, and the implementation of new communications infrastructure.

The seasonal variation of hydrological conditions within New England traditionally peak during the spring and fall timeframes and are lowest during the summer season. Small non-dispatchable and run-of-river hydro-electric facilities are seasonally rated against historical stream flow data, and as such, their monthly capacity ratings reflect the seasonal variations in regional hydraulic conditions. Conventional hydro facilities, with pondage or storage capability, are not seasonally capacity de-rated, but they can become energy limited during the dry summer months. These energy limitations are accounted for in daily dispatch.

---

[211] The approved changes to the Market Rule provided greater flexibility for the dispatch of Active Demand Resources. In particular, starting June 1, 2010, the ability to dispatch a resource for a portion of its Capacity Supply Obligation(CSO) and beginning June 1, 2011 the dispatch of resources on a Dispatch Zone basis. These two features alone allow for a more efficient and reliable use of DR.

[212] The Critical-Peak Demand Resource type will be eliminated as of the Capacity Commitment Period beginning on June 1, 2012. Market Participants with Critical Peak Demand Resources must convert those resources to a different Demand Resource type. This change was introduced to mitigate the inherent uncertainty of managing a resource that is responding in real-time without provisions for telemetry.

Reliability Assessment Analysis

The calculated summer Deliverable Reserve Margin based on generator and demand resources is 20.9 percent of the reference load forecast in 2009, and will be 16.7 percent in 2010 assuming no changes in capacity. Beginning in 2010, the margins reflect the resources that have obligations to serve the Regional capacity needs, as a result of ISO-NE's FCAs. In 2011, the Deliverable Reserve Margin increase to 30.2 percent, primarily due to the fact that the obligations for the FCA2 for the 2011/2012 timeframe reflect the clearing of increased amounts of demand resources, internal generating capacity and imports. In addition, those obligations for the FCA1, for the 2010/2011 timeframe, which is reflective of the 2010 margins, have been prorated downward to more closely match the ICR; the 2011/2012 FCM obligations, which is reflective of the 2011 margins, will likely be lower after prorating. It was assumed that resources with obligations for 2011 will remain in place through the end of the study period. Without any assumed new capacity resources, the deliverable Reserve Margins declines after 2011 to 11.4 percent by 2018.

New England does not have a particular capacity or Reserve Margin requirement; rather it projects its capacity needs to meet the NPCC once–in-ten-year LOLE resource planning reliability criterion. The capacity needs to meet this criterion are purchased through annual auctions (FCAs) three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions (ARAs) prior to the commencement year, in order to readjust installed capacity purchases and ensure adequate capacity will be purchased to meet system needs. Therefore, ISO-NE does not expect to face any installed capacity shortages in the future.

To develop installed capacity requirements to meet the once-in-ten-year disconnection of firm load resource planning reliability criterion, ISO-NE takes into account the random behavior of load and resources in a power system, and the potential load and capacity relief obtainable through the use of various ISO-NE Operating Procedures.

The amount of existing certain internal generating and demand resource capacity assumed available to meet the installed capacity requirement is 33,417 MW in the summer 2009, decreasing to 31,849 MW for the summer of 2010, increasing to 33,651 MW in 2011, and remaining constant at 33,244 MW through each summer to 2018. The total deliverable capacity to serve load, including planned resources and net imports and exports, is 33,703 MW in the summer of 2009, decreasing to 32,873 MW in the summer of 2010. The total deliverable capacity to serve load in 2009 reflects the claimed capability of all generation within New England, while the total deliverable capacity to serve load beginning in 2010 reflects only the FCA obligations required to satisfy the ICR. By the summer of 2018, the total deliverable capacity to serve load, including net imports and exports, is 34,499 MW.

The amount of resources external to New England reflects capacity imports of 401 MW in 2009, 899 MW in 2010, 2,298 MW in 2011 and 2012, and then decreases to only 6 MW by 2018.

For the year 2009/2010 and the FCM capability years 2010/2011 through 2018/2019, Table 1 summarizes the:

- 50/50 Peak Load Forecast

- Actual ICR
- Representative Future Net ICR[213]
- Resulting Reserves
- Assumed Existing ICAP, and
- Potential Surplus ICAP

The ICR values for the year 2009/2010 and the FCM capability years 2010/2011 through 2011/2012 were approved by FERC. ISO-NE files the ICR for 2012/2013 with FERC in July 2009. The representative future net ICR values for 2013/2014 and beyond were calculated using the following assumptions:

- The availability of 1,665 MW of total tie-line benefits from the three neighboring balancing authority areas of Québec, the Maritimes, and New York
- The 2009 CELT Report loads
- Generating resource capability ratings and outage rates based on ratings and rates developed for calculating the ICR for the 2012/2013 capability year
- Demand resource assumptions based on the types and amounts of capacity that have qualified as existing resources for the third FCA and availability-performance expectations developed by the NEPOOL Power Supply Planning Committee.

As shown in Table 1, the resulting reserves exhibit an increasing trend from 2012/2013 at 10.1 percent to 2018/2019 at 11.3 percent. This increase in resulting reserves percentage is a result of assuming a fixed amount of tie benefits through time. As the system load increases and the tie benefits stay constant, the installed capacity needed to meet the resource adequacy planning criterion would increase as a percentage of the peak load. The percentage resulting reserve associated with the actual ICR for 2009/2010, 2010/2011, and 2011/2012 are three to four percent higher than the percentage values for the rest of the years because the Regional System Plan's 2008 (RSP08) load forecasts were used to calculate these ICRs, but the lower RSP09 load forecasts were used to calculate their resulting reserves percentages.

Table 1 shows that no additional capacity would be needed to meet the representative future net ICR until after 2018/2019, assuming the 37,283 MW of capacity that has cleared the FCA2 with supply obligations is in commercial operation by the summer of 2011 and that it continues to clear in the FCA each subsequent year thereafter.

The actual amounts of internal and external capacity to be procured through the FCM process for future years will continue to be determined according to established FCM market rules. The amount of additional capacity and the installation timing to meet the future requirements will depend on future expected system load and resource conditions. Any changes in these conditions will be reflected in future RSPs and FCAs. Projected capacity deficiencies can be mitigated though FCM, one year prior to time period of concern.

[213] While the representative future net ICR values presented do not indicate the amount of capacity the Region must purchase, these values provide stakeholders with a general idea of the resource needs of the Region.

Table 1
50/50 Peak Load Forecast, Actual ICR and Representative Future Net ICR, Resulting Reserves, Assumed Existing ICAP, and Potential Surplus ICAP for 2009/2010 through 2018/2019

FCM Capability Period or Year	Forecast 50/50 Peak Load (MW)	Actual[(a)] ICR and Representative Future Net ICR[(b)]	Resulting Reserves (percent)[(c)]	Assumed Existing ICAP[(d)]	Potential Surplus ICAP[(e)]
2009/2010	27,875	31,823 (A)	14.1	33,921	2,098
2010/2011	28,160	32,137 (A)	14.1	34,021	1,884
2011/2012	28,575	32,528 (A)	13.8	37,021	4,493
2012/2013	29,020	31,965 (A)	10.1	37,021	5,056
2013/2014	29,365	32,411 (R)	10.4	35,091	2,680
2014/2015	29,750	32,901 (R)	10.6	35,091	2,190
2015/2016	30,115	33,370 (R)	10.8	35,091	1,721
2016/2017	30,415	33,757 (R)	11.0	35,091	1,334
2017/2018	30,695	34,120 (R)	11.2	35,091	971
2018/2019	30,960	34,454 (R)	11.3	35,091	637

(A) = Actual Installed Capacity Requirement
(R) = Representative Future Net Installed Capacity Requirement

a. "Actual Installed Capacity Requirement" for 2009/2010 is the ICR for New England. "Actual Installed Capacity Requirement" for 2010/2011 through 2012/2013 is the ICR which the FCM procurement is based upon.

b. "Representative Future Net ICR" is the representative ICR for the Region, minus the tie-reliability benefits associated with the HQICCs. The ICR value for 2010/2011 reflects the value approved by FERC in its March 11, 2009, *Order* Accepting *Filing of Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits and Related Values for the 2010/2011 Capability Year and Related Market Rule Revisions.*[214] The ICR value for 2011/2012 reflects the value approved by FERC in its November 7, 2008, *Order Accepting, With Conditions, Proposed Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits, and Related Values.*[215] For the 2012/2013, the net ICR value represents the value filed with FERC in July 2009 and is pending FERC approval. For the 2013–2019 capability years, representative net ICR values are presented reflecting the amount of capacity resources needed to meet the resource adequacy planning criterion.

c. Resulting Reserves (RRs) are the amount of capacity the system has over the expected system-wide peak demand. RRs often are expressed as a percentage of the annual 50/50

[214] http://www.iso-ne.com/regulatory/ferc/orders/2009/mar/er09-640-000_3-11-09_order_accepting_icr_rev.pdf
[215] http://www.iso-ne.com/regulatory/ferc/orders/2008/nov/er08-1512-000_11-7-08_2011-2012_icr_order.pdf

peak-load forecast. They are calculated by subtracting the 50/50 peak-load forecast for the year from the ICR and dividing that total by the 50/50 peak-load forecast. The RRs sometimes are mistakenly referred to as required reserves, although ISO-NE does not have a predefined required percentage for installed reserve capacity.

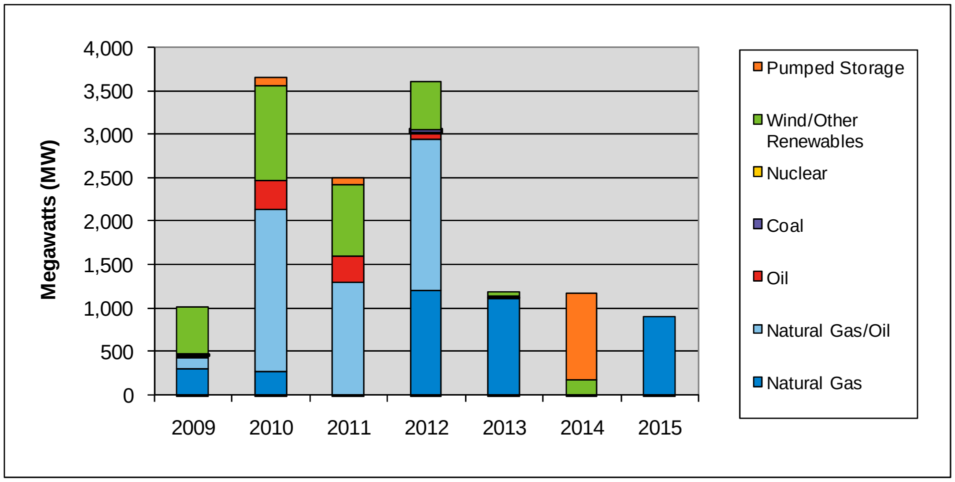
d. "Assumed Existing ICAP" for 2009/2010 reflects only supply and demand-side resources, capacity additions, net of imports and exports, and does not include tie-benefits and load and capacity relief from Emergency Operating Procedures (EOPs). "Assumed Existing ICAP" for 2010/2011 and 2011/2012 reflect the amount of capacity resources that have cleared the FCA for those years but with reserve-margin gross up for New York Power Authority imports (NYPA) and demand resources removed. The 2012/2013 value is based on the 2011/2012 value. The values for 2013–2019 are based on the 2011/2012 value but with non-grandfathered ICAP imports removed and the full amount of RTEGs included.

e. "Potential Surplus ICAP" represents an approximation of the future capacity situation, assuming no resource additions or attritions during the study period. It is assumed that capacity that cleared in FCA #2 (excluding the non-grandfathered ICAP imports and adjusted for other factors described in footnote (d) will be in service in 2012 and will continue to be in service until the end of the study period.

ISO-NE 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 in 2009. The 2,000 MW amount is based on the results of the 2009/2010 ICR calculation, in which ISO-NE has analyzed the expected 2009/2010 system conditions of the neighboring Control Areas, as reflected in the most recent Northeast Power Coordinating Council (NPCC) 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 the Maritimes, New York, and Quebec. Tie benefits are calculated annually, based on projected system conditions within New England and its neighboring control areas. ISO-NE also participates in a Regional reserve sharing group with NPCC and has a shared activation of reserves agreement for up to 300 MW.

ISO-NE has a total of 13,833 MW of proposed projects in its Generator Interconnection Queue (dated March 15, 2009) with in-service dates ranging from 2009 to 2015. These resources could help meet New England's future FCM needs. Historically, approximately 20 percent of projects in the Interconnection Queue had gone into commercial operation. As noted earlier, this 20 percent value has been applied to the amount of projected Conceptual Capacity Resources. This 20 percent Confidence Factor represents the amount of Conceptual Capacity that may become commercialized within the Region, starting in the year 2010. This 20 percent Confidence Factor is held constant going forward in time. In the summer of 2018, this equates to approximately 2,492 MW. The capacity of projects in the ISO-NE Interconnection Queue, by fuel type and in-service date, is illustrated in Figure 1.

Figure 1
ISO-NE Generator Interconnection Queue Capacity by Project Type



There is no difference in how ISO-NE treats short-term (i.e., 1–5 years) and long-term (i.e., 6–10 years) Reserve Margin requirements.

The most significant changes from last year's assessment include increases in demand resources (DR) and FCM import obligations. The amount of DR has increased significantly since the *2008 NERC Long-Term Reliability Assessment*, with the projection for 2009 increasing by 600 MW, from 1,820 MW to 2,420 MW. Imports totaling approximately 2,300 MW are assumed to be available for the 2011–2012 FCM. This is about 1,400 MW more than imports available for 2010–2011.

ISO-NE also conducted an operable capacity analysis based on the 90/10 peak-load forecast for its 2009 Regional System Plan. That analysis is shown in Table 2. The 2009 capacity consists of both generating and demand resources, and the capacity of the remaining years is the installed capacity requirement for those years assuming that ISO-NE purchases the exact amount of resources to meet the installed capacity requirements. A total of 2,000 MW[216] of operating reserves[217] are assumed for all years. A total of 2,100 MW of supply-side outages were assumed for all years based on historical observations. The results do not reflect resource (generating unit and demand resource) additions, retirements, or deactivations that could potentially occur during the planning period.

Table 2 shows the operable capacity margins for the summer of 2009 through the summer of 2018. Negative operable capacity margins are projected for all summers, ranging from a high of -123 MW in the summer of 2010 to a low of -1,155 MW in the summer of 2012. The operable

[216] The 2,000 MW of operating reserves is equal to the largest loss of source contingency at 1,400 MW (the HQ Phase II HVdc facility) plus one half the second largest loss of source contingency (a 1,200 MW nuclear unit) or equivalently 600 MW.

[217] Operating reserve is equal to 100 percent of the largest contingency (largest source can be either a generator or transmission (path)) plus 50 percent of the second largest contingency (second largest source can either be a generator or transmission (path)).

capacity margin for the summer of 2009 is negative at 152 MW. When New England is short of operable capacity, ISO-NE will implement Operating Procedure No. 4 — *Action during a Capacity Deficiency* (OP4). OP4 is designed to provide additional generation and load relief needed to balance electric supply and demand while striving to maintain appropriate levels of operating reserves. Capacity available under OP4 includes voltage reduction and emergency assistance from neighboring balancing authorities. For the purposes of ISO-NE operable capacity studies (not reflected in Table 2), 2,000 MW of emergency assistance is assumed to be available through 2009. That number changes to 1,860 MW beginning in 2010.

Table 2
Projected ISO-NE Operable Capacity Margins for Summer 2009 – 2018, Assuming 50/50 Peak Loads (MW)

Capacity Situation (Summer MW)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak Load (50/50)	27,875	28,160	28,575	29,020	29,365	29,750	30,115	30,415	30,695	30,960
Operating Reserves	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,00
Total Requirement	29,875	30,160	30,575	31,020	31,365	31,750	32,115	32,415	32,695	32,960
Capacity	31,823	32,137	32,528	31,965	32,411	32,901	33,370	33,757	34,120	34,454
Assumed Unavailable Capacity	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)
Total Net Capacity	29,723	30,037	30,428	29,865	30,311	30,801	31,270	31,657	32,020	32,354
Operable Capacity Margin[(a)]	(152)	(123)	(147)	(1,155)	(1,054)	(949)	(845)	(758)	(675)	(606)

"Operable Capacity Margin" equals "Total Net Capacity" minus "Total Requirement."

Significant transmission projects which have been approved since last year's assessment include the Vermont Southern Loop, the updated Maine Power Reliability Program, Greater Rhode Island Reinforcements, and the New England East West Solution (NEEWS) projects.

ISO-NE utilizes operating procedures to address real-time problems with resource adequacy. Actual resource unavailability due to fuel interruptions or other conditions are recorded and then used to formulate forward-going resource availability assumptions for input into long-range resource adequacy studies, which are subsequently conducted on an annual basis.

Figure 2 shows New England's 2009 summer installed capacity (MW) and overall contribution percentages. Total 2009 summer installed capacity is 31,433 MW. Due to the major contribution to overall installed capacity from gas-fired facilities (11,948 MW at 38.0 percent),[218] fuel supply disruptions to Regional gas-fired facilities can have a major impact on resource adequacy. However, because the majority of these facilities are directly connected customers of large Regional interstate gas pipelines (a total of five pipelines into New England), the simultaneous loss of gas supply or downstream-transmission to all five of these pipelines is improbable. The temporary loss of gas supply or gas transmission capacity on any individual pipeline could still affect resource adequacy, although at a much smaller and localized level. Due to the interruptible characteristics of their gas supply and transportation arrangements, longer-term gas supply or transmission disruptions would first impact the Regional gas-fired power generation sector, which in turn, would need to be mitigated by increased levels of oil-fired generation to replace lost, gas-fired energy production. In general, the low priority nature of Regional gas-fired generators' fuel supply and transportation entitlements can create temporary operable capacity problems, primarily during winter, when most of the Regional pipelines are fully subscribed and flowing natural gas to firm customers of the Regional gas LDCs.

Due to the major contribution to overall installed capacity from oil-fired facilities (7,743 MW at 24.6 percent), fuel supply disruptions to Regional oil-fired facilities (some of which are dual-fuel capable) could have a significant impact on resource adequacy, although on-site oil storage inventories at these facilities is usually in the 5–15 day supply range. It is assumed that most dual-fuel units would swap over to their unconstrained fuel supply. Therefore, temporary fuel supply disruptions to oil-fired facilities should not be problematic; however, longer-term fuel supply disruptions would need to be mitigated by increased levels of gas-fired generation to replace lost, oil-fired energy production.

Approximately 7,600 MW of installed capacity is dual fuel capable, burning a combination of natural gas and heavy or light fuel oil. These dual fuel units can contribute to system reliability when either natural gas or oil supplies become constrained, by switching over to their unconstrained fuel source.

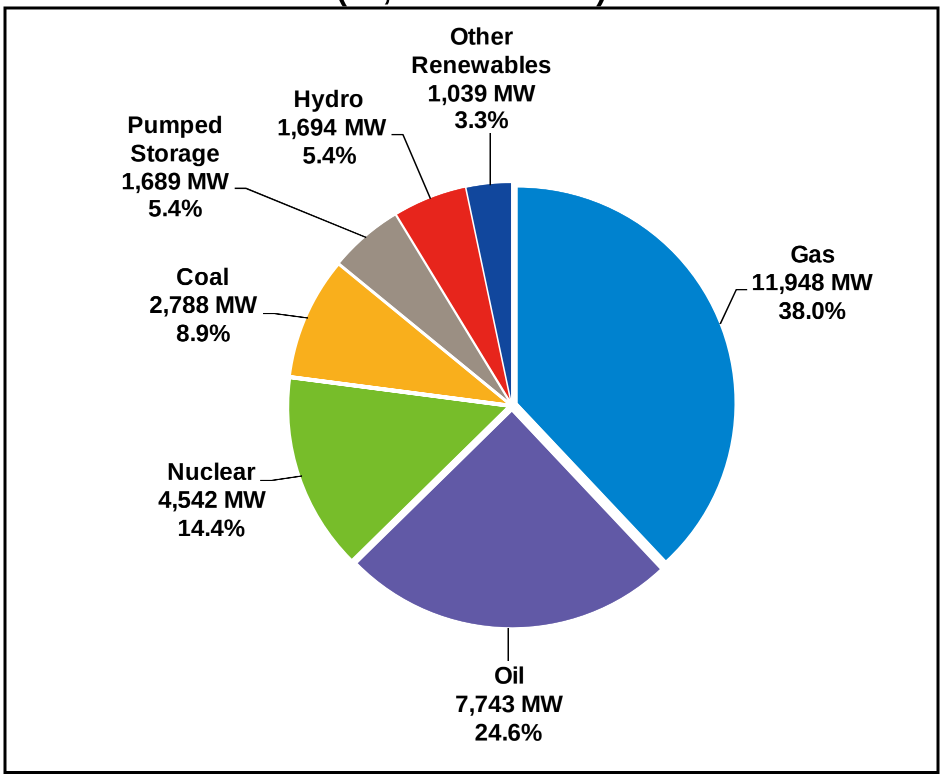
Due to the relatively minor contribution to overall installed capacity from coal facilities (2,788 MW at 8.9 percent), fuel supply disruptions to Regional coal facilities could have some impact on resource adequacy, although on-site coal inventories is usually in the 15–30 day supply range. Therefore, temporary fuel supply disruptions at coal facilities should not be problematic, however, longer-term fuel supply disruptions would need to be mitigated by increased levels of oil or gas-fired generation to replace lost, coal-fired (base-load) energy production.

Although the installed capacity of hydro-electric facilities is relatively small (1,694 MW at 5.4 percent) Regional drought conditions could cause a temporary disruption in hydro-electric

[218] Approximately 2,300 MW of primary fueled, gas-fired facilities have dual fuel capability, which can burn a secondary fuel source of either heavy or light oil.

energy production, which again would need to be supplemented by increased levels of other types of fossil-based generation.

Figure 2
2009 Installed Summer Capacity (MW and percent)
(31,433 MW Total)



ISO-NE does not consider any energy-only, existing-uncertain wind or transmission-limited resources in its resource adequacy assessment.

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 system reliability.

Variable resources are considered similar to other units in ISO-NE's resource adequacy assessment in that their ratings are based on expected (seasonal) performance.

ISO-NE has instituted several processes to aid in the integration of variable resources into ISO planning and operations. ISO-NE 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 into New England's power grid. ISO-NE 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, ISO-NE may also provide performance and impact evaluations on various transmission and generation scenarios from both a reliability and economic perspective.

ISO-NE 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.

ISO-NE 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.

ISO-NE is not aware of any future unit retirements, and does not make projections about potential retirements, although the potential for retirements may be considered part of system design. As noted earlier, nuclear plant relicensing and once-through cooling issues are probably the only major open retirement issues at this time. In the event the owners of these nuclear plants do not file for a renewal of their NRC Operating Permits or the owners of these fossil-steam units that use once-through cooling choose to retire their affected facilities, this lost capacity will be procured through the FCM, either in the form of new generation, imports, or Demand Response. At several fossil-steam units, the replacement of once-through cooling systems with closed-loop cooling systems (i.e., cooling towers) would be managed through planned outages which would be coordinated by ISO-NE to minimize the impact on system reliability.

ISO-NE currently addresses generation deliverability through a combination of transmission reliability and resource adequacy analyses. Detailed transmission reliability analyses of sub-areas of the New England BPS 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 the NERC Transmission Planning requirements and assure the transmission system is planned to sufficiently integrate generation with load.

New England's methodologies for determining its Installed Capacity Requirement, which is procured through the FCM, are designed to recognize transmission constraints and to procure generation that is incrementally useful to serve load. This "*transmission-deliverability-*

analysis"[219] is done for both internal and external capacity resources. In addition, the FCM has strong financial incentives for internal and external resources (for both supply and demand-side resources) to maintain their availability and deliver their contractual capacity obligations when called upon to do so by ISO-NE. These FCM *"pay-for-performance"* penalties can significantly diminish forward-going FCM revenues.

Transmission plans have been developed to serve load growth throughout the New England Region. This includes service to load areas in Maine, New Hampshire, Vermont, Western Massachusetts, Southeastern Massachusetts, Northeastern Massachusetts, Greater Rhode Island, and Connecticut. Future resources have only been included in reliability assessments if they have received an obligation through the FCM, if they are contractually bound by a state-sponsored RFP, or if they have a financially binding obligation pursuant to a contract. However, assessments still consider reasonable planned and unplanned outdates of the future resources in the same manner as existing resources.

The impact of new generator interconnections or additions to transmission system topology on both transient performance and voltage or reactive performance is routinely analyzed and plans are developed to mitigate concerns as part of the interconnection process. Operating studies to develop operating guides are generally performed under both heavy and light load conditions to assess the impact on transient performance and 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, which 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 – *Load Power Factor Correction* (OP17) defines acceptable Load Power Factor requirements for various subregions within New England. The procedure is designed to ensure adequate reactive resources are available in subregions by managing reactive demands. Furthermore, when transfer limits are developed for voltage or reactive constrained subregions, ISO-NE will develop detailed operating guides that cover all relevant system conditions to ensure reliable operation of the BPS. After determining the acceptable transfer limits, a 100 MW margin is added to them, primarily for regulating margin to assure these areas will maintain acceptable pre- and post-contingency voltage performance. In some areas, such as Boston and Connecticut, specific operating guides have been developed to ensure sufficient reactive resources are committed to operate these areas 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. In addition, the voltage must not sag below 80 percent of normal voltage for a duration longer than 250 milliseconds within the ten seconds following the fault. This guideline is applied when developing transmission transfer limits for the BPS in New England.

[219] Currently referred to under the existing ISO-NE FCM Market Rules as the "Capacity Network Resource Capability" or CNRC.

Currently, New England does not have interconnection requests for new resources in the six to ten year time frame. There are no transmission elements that have a long-lead time for procurement.

At this time, there are no plans to install more Under Voltage Load Shedding (UVLS) in New England. Currently, Northern New England has the potential to arm approximately 600 MW of load shedding as part of UVLS. However, it is important to recognize a significant portion of this load shedding is normally not armed and is only armed under severe loading conditions with a facility already out of service. Presently, two significant projects which are anticipated being in service by 2012 will either completely eliminate the need for the UVLS or significantly reduce the likelihood of depending on such schemes. These projects are the Vermont Southern Loop and the Maine Power Reliability Program (MPRP).

ISO-NE addresses the loss of a major import path through its local operating reserve requirement, which is calculated daily, and set to be equal to or larger than the largest credible loss of supply due to loss of an import path or other resource. Daily unit commitment is factored into the determination of projected loads, planned outages, reasonably anticipated unplanned outages, and local operating reserve requirements.

ISO-NE's Operating Procedure No. 21 – *Action during an Energy Emergency* (OP21) addresses energy emergencies, which may occur as a result of sustained national or Regional shortages in fuel availability or deliverability to New England's generation resources. Because fuel shortages may impact the Region's ability to fully meet system load and ten minute operating reserve for extended periods of time, actions may need to be taken in advance of a projected energy emergency. OP21 specifies actions to commit, schedule, and dispatch the system in such a way as to preserve stored fuel resources in the Region to minimize the loss of operable generating capability due to fuel shortages. OP21 can be implemented to mitigate most types of fuel shortages impacting the electric sector, no matter what the triggering event may have been, i.e., destruction of oil and natural gas infrastructure due to hurricanes, loss of major transmission pathways due to earthquakes, or damage from ice storms, frozen harbors, frozen coal piles, oil, and LNG embargoes.

The New England Area is currently not experiencing a drought. However, in the event the Region was experiencing an extended drought, traditional hydro-electric stations (1,694 MW in total) could be capacity constrained. A nuclear station (~700 MW) and several other fossil stations could also be capacity limited due to lack of cooling water or other (*heat-related)* environmental issues. As noted earlier, due to the relatively small contributions to the Region's overall installed capacity from hydro-electric facilities, drought conditions could cause a temporary disruption in hydro-electric, fossil-based and (river-cooled) nuclear energy production, which would in turn need to be supplemented by increased levels of other generation.

New England does not have any guidelines for on-site, spare generator step-up (GSU) or autotransformers. New England has had numerous discussions on possible policies to address these concerns with respect to autotransformers. In addition, some of New England's Transmission Owners have joined the EEI initiated Spare Transformer Equipment Program.

As part of the New England Regional System Planning process, system needs have been identified in all six states of the New England Region. The system needs assessments and resulting system solutions, which form the basis of the New England project listing, and ensure conformance with NERC Standards TPL-001 through TPL-004. Some of the larger plans to address future system needs that are currently in process are listed below. More information on these projects can be found in the 2008 Regional System Plan (RSP), published last fall, as well as the 2009 RSP, which is scheduled for completion this coming fall.

Maine — The Maine Power Reliability Program (MPRP) analyses have identified the potential for difficulties in moving power into and through Maine to various load pockets spread throughout the state. The existing system is highly dependent upon the 345 kV lines which consist of only a single 345 kV path in the north and two parallel 345 kV paths in the south. Furthermore, there are a limited number of 345/115 kV autotransformers to supply the 115 kV network. System studies have shown that loss of a single 345 kV transmission line or autotransformer can yield unacceptable results, which are only further exacerbated when a second contingency is contemplated. Additionally, there are a number of Special Protection Systems (SPS) which have become a significant concern in real-time operations and have also been shown to become insufficient in the future. The largest of these pockets, which is facing the most immediate concerns, is the area in southern Maine along the seacoast, which includes the Portland Area. Another area of concern in Maine, often referred to as western Maine, is challenged to supply area load, which includes a number of large paper mills, especially when these loads are modeled at their contractual limits.

The MPRP effort 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 the Three Rivers switching station located in southern Maine. This project also adds a number of 345/115 kV autotransformers and creates a new 115 kV path into western Maine.

New Hampshire — A ten-year study of the New Hampshire Area has initially identified the potential for system concerns throughout much of the state for numerous different contingencies and resource outages in the future. The more significant concerns are related to serving the southern and seacoast areas, which are served from a limited number of autotransformers and insufficient 115 kV networks. Further concerns are related to moving power into central New Hampshire, which is served through a 115 kV path and serving northern New Hampshire following the loss of the single 230/115 kV autotransformer at Littleton. The study of New Hampshire's system is under review due to recent reductions in the Regional load forecast. These concerns are planned to be addressed through the addition of new autotransformers in the seacoast, southern and northern areas, coupled with new transmission. The exact configuration of the new transmission is under review due to the recently revised load forecast.

Vermont — The updated Vermont Long Range Plan (LRP) has identified the potential for system concerns moving power through the state for various future contingencies. Due to limited generation supplies and a significant load concentration in the northern part of the state, power must be imported over significant distances to supply this area. Therefore, when either a southern 345 kV line or a 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 to these future problems include providing additional reactive support, adding additional autotransformers, and reconductoring a number of 115 kV lines.

Connecticut — The New England East West Solution (NEEWS) studies have included the evaluation of 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. Past analyses had indicated that Connecticut would need either transmission improvements or over 1,500 MW of supply or demand-side resources by 2016. Past studies also showed that Connecticut had internal elements that limited east-west power transfers across the central part of the state. The movement of power from east to west in conjunction with higher import levels to serve Connecticut had resulted in overloads of transmission facilities located within the state. Updated assessments have shown that resources planned, and obligated by contract, for Connecticut are sufficient to meet reliability requirements for 2010 and 2011, assuming there are no supply-side retirements. In the absence of additional planned resources, the proposed solution involves new interstate transmission lines from central and western Massachusetts into Connecticut, which eliminate the existing constraints.

Springfield, (MA) — The NEEWS studies, resulting in part in the Greater Springfield Reliability upgrades, have found that local double circuit tower (DCT) outages, stuck-breaker outages, and single-element outages result in severe thermal overloads and low-voltage conditions. These overloads are exacerbated when Connecticut transfers increase, especially with a major 345 kV line out of service. The proposed solution eliminates a number of multi-circuit towers in the area and installs a new 345 kV line between Ludlow, Massachusetts and north-central Connecticut.

Rhode Island — The Greater Rhode Island studies, in conjunction with the NEEWS studies, have identified significant thermal 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 line-out conditions, the next critical contingency would result in numerous thermal and voltage violations, and possibly the shedding of over 500 MW of load. This is proposed to be resolved by transformer additions, a new 345 kV line between West Farnum and Kent County, and the fact that the additional central Massachusetts to Connecticut 345 kV line (mentioned above) loops into the West Farnum substation.

There are no known reactive power-limited areas in the New England transmission system. Transmission planning studies have ensured adequate reactive resources are provided throughout New England. In instances where dynamic reactive power supplies 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 typically applies a 100 MW margin to transfer limits.

New England already has a number of installations of new technologies. These include two STATCOMs, voltage source converter-based HVdc, variable reactors, a short section of gas-insulated transmission line (GITL), and DVAR. Presently there are no specific plans for the additional use of such technologies in future projects, but they are always under consideration as tools to manage future system concerns.

For the most part, New England's short-circuit concerns occur at voltages less than 230 kV. In many instances, the short-circuit concerns at these lower voltages are resolved through changing generator interconnections to be at higher voltages, system reconfigurations, or by operating equipment in a normally open state to increase the impedance between the network and the subject bus. New England has been meeting with various manufacturers over the years to acquire information on the possible application of *short-circuit limiters* to resolve these concerns. To date, such technologies have not been employed.

The New England utilities have been working to upgrade and update their equipment over time on a case-by-case basis. While older equipment remains in service, there are no known risks to the continued operation of this equipment. Transmission system plans will often consider the potential retirement of older generation and determine the upgrades, if necessary, to allow for such retirements to occur.

ISO-NE does not anticipate any impacts on reliability resulting from economic conditions. As far as capacity is concerned, ISO-NE does not expect any project cancellations or deferrals. ISO-NE has a capacity market that pays for resources that contribute capacity to the system, and economic conditions do not impact the amount of money paid for contracted capacity. This means that projects that are expected to go into commercial operation in summer 2009 are likely to be in service as planned. With respect to loads, the economic recession has resulted in lower forecasted peak loads over the ten-year study period, which is even lower than last year's load forecast. Therefore, ISO-NE's ability to serve the load has increased, which improves system and sub-area reliability.

Region Description

ISO New England Inc. is a Regional Transmission Organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day 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 BPS. 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 electric system.

New York Independent System Operator (NYISO)

Executive Summary

The 2009 Comprehensive Reliability Plan (CRP)[220] completes the NYISO's reliability planning cycle known as the Comprehensive Reliability Planning Process (CRPP). The CRPP encompasses a ten-year planning horizon and evaluates the future reliability of the New York BPS. In order to preserve and maintain system reliability, the NYISO in conjunction with Market Participants, identifies the reliability needs over the planning period and issues its findings in the Reliability Needs Assessment (RNA). The CRP evaluates a range of proposed

[220] 2009 Comprehensive Reliability Plan (Final Report, May 19, 2009) located at http://www.nyiso.com/public/services/planning/reliability_assessments.jsp

solutions to address the needs identified in the RNA and sets forth the plans and schedule for the implementation of those solutions.

The 2009 CRPP did not identify any reliability needs. Therefore no solutions are necessary over the ten-year planning horizon 2009–2018. The findings indicate that anticipated capacity supply (42,536 MW) will exceed the forecasted peak load (35,658 MW) by 994 MW in 2018, after factoring in the presently required 16.5 percent Installed Reserve Margin (IRM). There are three major reasons this year's CRPP did not identify any reliability needs over the planning horizon: 1) a reduction in peak load forecast due to both slower economic growth and projected energy efficiency gains; 2) an increase in generation additions and Special Case Resource (SCR) participation; and 3) fewer planned retirements. Moreover, the forecasted load utilized in the 2009 RNA last fall did not anticipate the current economic recession, which is further reducing the anticipated peak load and energy use.

Introduction

The NYISO is a not-for-profit corporation responsible for operating New York State's bulk electricity grid, administering New York's competitive wholesale electricity markets, and conducting comprehensive long-term planning for the state's electric power system. The NYISO is regulated primarily by the Federal Energy Regulatory Commission (FERC).

In 2005, the NYISO implemented the Comprehensive Reliability Planning Process. The CRPP was incorporated into a biennial Comprehensive System Planning Process (CSPP) that was approved by FERC. Created in response to FERC Order 890, the CSPP begins with a Local Transmission Planning Process (LTPP), conducted by each New York Transmission Owner. The proceeds to the control area-wide CRPP to determine reliability needs and solutions, and concludes with a new economic planning process. The Congestion Analysis and Resource Integration Study (CARIS) is to evaluate congestion on the transmission system and analyze projects to alleviate that congestion.

The first step in the CRPP is the Reliability Needs Assessment which evaluates the adequacy and security of the bulk power system over a ten-year Study Period.

The results of the 2009 RNA indicate that resources needed to meet the electricity demand of New York State are expected to continue to exceed demand. New York has 42,077 MW of generation and demand-side resources for 2009 with a peak load forecast of 34,059 MW. After factoring in the required 16.5 percent Installed Reserve Margin (IRM), supply still exceeds demand by 2,398 MW. The RNA report anticipates that peak load will grow to 35,658 MW by 2018 while supply will increase to 42,536 MW.

Although the 2009 RNA provides some assurance, there will be a reliable supply of electric energy to serve New York's customers over the next 10 years. There are emerging energy challenges facing the state and the nation that the NYISO will continue to monitor and will notify policy makers if there is an anticipated impact to the system reliability outlook. These issues include:

Implementation of new programs to control NO_x emissions from fossil-fueled generation on high electric demand days that could render some units unavailable and limit others to reduced output at times of peak demand.

Unexpected Retirement of Certain Generation Facilities

The 2009 RNA assumes the effective implementation of state-sponsored energy efficiency programs. Should these programs not proceed or perform as planned reliability needs may arise as soon as 2017.

Regional Greenhouse Gas Initiative (RGGI) – if the RGGI allowance market operates as expected, reliability will not be negatively impacted. However, the level of RGGI allowance costs, the price spread among different fuels used by generators, and other environmental program compliance costs have an interrelated and cumulative effect on high carbon emitting units, and potentially, the availability of generators to maintain electric system reliability.

Demand

Last year's compound annual energy growth rate was 1.18 percent. This year's compound annual energy growth rate is 0.59 percent. Last year's compound annual summer peak growth rate was 0.94 percent. This year's compound annual summer peak growth rate is 0.68 percent. The reduction in compound annual growth rates for energy and summer peak demand results from a weak economy and an acceleration of state energy efficiency activity.

The 50th percentile forecasts of summer peak demand assume normal weather. The economic assumptions are that economic growth will be negative in 2009, flat in 2010, with a modest recovery in 2011. The NYISO used coincident subregional peak demand information in its analysis. Resource evaluations are based on coincident peak demand for most elements.

The NYISO develops high and low forecasts at the 90th and 10th percentiles that account for the observed historic variation in actual annual energy and seasonal peak demand due to the joint effects of weather and the economy.

The State of New York has recently completed an Energy Efficiency Portfolio Standard proceeding. The goal of the proceeding is to achieve annual energy reductions on the order of 26,000 GWh by 2015, approximately 15 percent of annual energy use projected for that year. The state has established an Evaluation Advisory Group (EAG) to determine the measurement and verification protocols that will be used to determine the success of the EEPS programs. The NYISO actively participates in the EAG.

Demand-Side Resources

The NYISO has two reliability-based 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 use through the voluntary reduction in demand from 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 use when asked to do so. No activations, other than tests, have occurred since August 3, 2006.

The Special Case Resources program also seeks to reduce power use through the reduction of demand from businesses and large power users. Companies, mostly industrial and commercial, sign up to participate as SCRs. The companies must, as part of their agreement, curtail power use, usually by shutting down when asked by the NYISO. In exchange, they are paid in advance for agreeing to cut power use upon request. No activations, other than tests, have occurred since August 3, 2006.

Effective July 1, 2007, NYISO implemented the Targeted Demand Response Program (TDRP) to respond to requests for assistance from a Transmission Owner (TO) by activating EDRP and ICAP/SCR resources on a voluntary basis in one or more subzones. TDRP currently applies to Zone J, New York City, where nine subzones have been defined. No TDRP activations have occurred since August 3, 2007.

The NYISO has two economic programs, the Day-Ahead Demand Response Program (DADRP) that allows energy users to bid their load reductions, or "megawatts", into the NYISO's Day-Ahead energy market as generators do and the Demand-Side Ancillary Services Program (DSASP) that allows energy users to provide ancillary services such as Operating Reserve and Regulation. DADRP bidding and scheduling activity remains frequent, but is limited to only a handful of resources. There are no resources currently enrolled in DSASP.

Demand Response Registration[221]

Data on Demand Response participation is divided into statistics on Demand Response: Resources; retail entities that register to perform load reductions; and curtailment service providers, which is a general term used to identify organizations that transact with the NYISO and represent end-use customers in Demand Response programs. The term "curtailment service providers" as used in this report refers to Responsible Interface Parties (RIPs) as defined in the Installed Capacity Manual, Demand Response Providers (DRPs) as defined in the DADRP Manual, and the entities defined in the EDRP Manual.

Table 1 identifies the number of curtailment service providers by organization type:

- Aggregators, who register customers to participate as part of an aggregation of several customers;
- Direct Customers, who register with the NYISO to participate in any of its markets, including its Demand Response programs;
- LSEs, who provide commodity service to retail customers; and
- TOs, the investor-owned transmission and distribution companies and public authorities located in New York State.

Table 1. Curtailment Service Providers by Organization Type Provider Type

[221] Summer Compliance Report on Demand Response Programs June 1, 2009 as reported to FERC. http://www.nyiso.com/public/documents/regulatory/filings.jsp.

Table 1 : Curtailment Service Providers by Type		
Provider Type	Count as of May 2009	Change from Dec 2008
Direct Customers	8	+1
LSEs	4	0
Transmission Owners	7	0
Totals	46	+4

Note to Table 1: As reported by the NYISO to the Federal Energy Regulatory Commission in its January 15, 2009 semi-annual report on the NYISO's Demand Side Management programs, which was filed with its report on new generation projects in the New York Control Area and Installed Capacity Demand Curves (January 2009 Report).

Table 2 presents a summary of registration statistics for EDRP, SCR, and DADRP, respectively, as of mid-May 2009.

Table 2 : Registration Summary (May 2009) by Program				
Program	Count	Load MW	Gen MW	Total MW
EDRP	377	213.4	116.1	329.4
SCR	3393	1996.1	244.4	2240.5
DADRP	50	331.4	0	331.4

Energy Efficiency

A reduction in peak load forecasts due to both slower economic growth and projected energy efficiency gains is realized in the demand forecasts for this study. The details of recently legislated energy efficiency initiatives are still being studied.

Generation

Figure 1 represents the 2009 Existing resources and the breakdown by fuel type in the New York Control Area ("NYCA") as published in the 2009 Load and Data report ("Gold Book").

Figure 1: 2009 NYCA Capability by Fuel Type

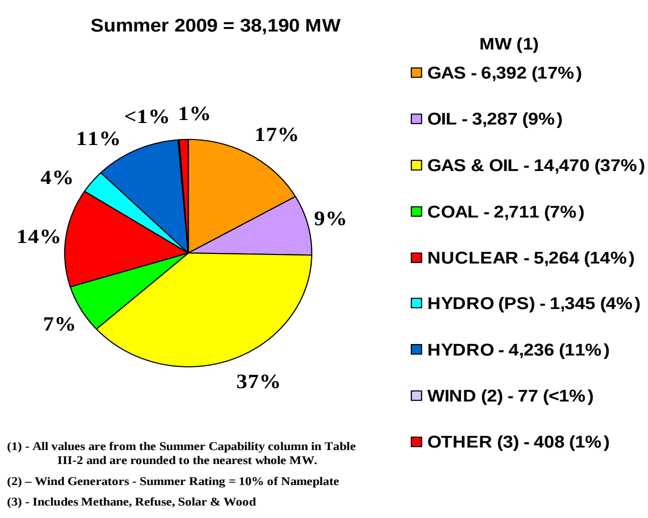
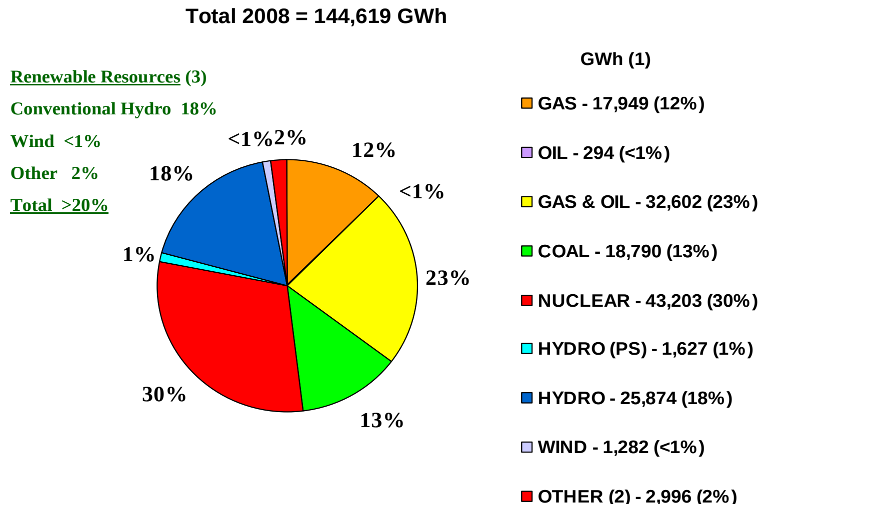


Figure 2 represents the 2008 New York Control Area total generation by fuel type.

Figure 2: 2008 NYCA Generation by Fuel Type



(1) - All values are rounded to the nearest whole GWh.

(2) - Includes Methane, Refuse, Solar & Wood

(3) – Renewable Resources do not necessarily match the NYS Renewable Portfolio Standard (RPS) Definition

(PS) – Pumped Storage

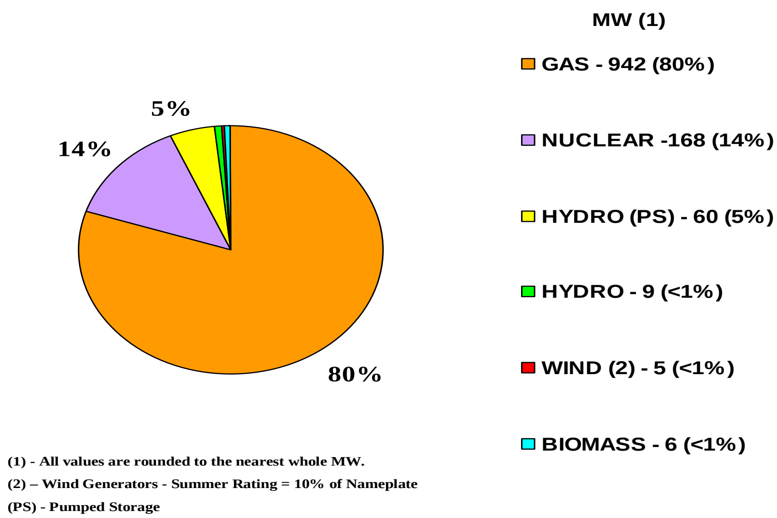
Intermittent resources, such as wind, are reported with a nameplate rating and an expected value for summer and winter capability that is based upon the 2003 NYSERDA Wind Study. The expected value of 10 percent is used for the summer capability rating for upstate wind projects and 30 percent for offshore wind projects. The winter expected capability based upon the study is 30 percent.

The NYISO maintains a list by Class Year[222] of proposed generation and transmission projects in the NYISO interconnection process. The interconnection process is a formal process defined by NYISO's tariffs by which the NYISO evaluates transmission and generation projects, submitted by Market Participants, developers, and other qualified organizations to determine their impact on system reliability.

Figure 3 represents the planned generation additions by fuel type that have met sufficient milestones for inclusion in the 2009 Gold Book. These projects have a high degree of certainty that they will come on-line as expected.

[222] The Class Year is the final step in the New York interconnection process where the system upgrade facilities, or "but for" facilities, are determined for proposed new interconnections and cost responsibility assigned.

Figure 3: Planned Capability by Fuel Type



Another 3,392 MW of proposed additions are listed under the Conceptual Capacity category. These are resource projects that have started the NYISO Interconnection process and are at various stages but at this time, it can not be determined which of these projects are viable and will proceed as planned.

The mix of resources in New York has changed since the inception of the NYISO's markets. A number of coal-fired units have retired and additions to the system have been predominantly natural gas-fired combined cycle or gas turbine units. In addition, a substantial amount of wind generation has been added in New York by virtue of the PSC-adopted Renewable Portfolio Standard (RPS). Accordingly, New York has maintained a relatively fuel diverse generating fleet to date. Specifically, 37 percent of the Summer 2008 NYCA capacity represents dual fuel (gas and oil) units, 17 percent gas units, 14 percent hydro units, 13 percent nuclear units, 9 percent oil units, 8 percent coal units, and 2 percent other units including wind.

The fuel diversity of the power supply system and its overall impact on fuel availability and prices needs to be monitored on a continuous basis, but it should be noted that planned additions of renewable resources within the State pursuant to its RPS have and will continue to contribute to fuel diversity. The NYISO will also monitor changes to the fuel supply infrastructure, such as new fuel gas pipelines and liquefied natural gas facilities. For additional information, review the NYISO's white paper on fuel diversity.[223]

Capacity Transactions on Peak

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the level of capacity imports from neighboring Control Areas allowed

[223] http://www.nyiso.com/public/index.jsp

without violating the LOLE criteria. For 2009, the amount is 3,160 MW, except for grandfathered contracts, these import rights are allocated on a first-come, first-served basis with a monthly obligation. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.[224]

Table 3 shows the net capacity transactions for long-term capacity contracts. For 2010 and 2011, the number indicates a net sale from the NYISO to the neighboring Control Areas. This outcome results from increased capacity sales to ISO-NE as a result of the implementation of their Forward Capacity Market. Resources that have sold capacity to an external Control Area are not qualified to participate in the NYISO ICAP market and are not counted as resources eligible to meet the NYISO's LOLE criteria for the period the capacity is sold.

Table 3: Net Capacity Purchases and Sales (MW)

Year	Net Capacity	Year	Net Capacity
2009	77.2	2015	460.2
2010	-123.8	2016	460.2
2011	-205.6	2017	460.2
2012	510.2	2018	460.2
2013	510.2	2019	460.2
2014	460.2		

Transmission

Con Edison's M29 project consists of a 345 kV cable from Sprainbrook to Sherman Creek across the Dunwoodie South Interface which is planned to be in service in May 2011.

The interface into New York City and Long Island from Westchester, New York, namely Dunwoodie South, could become significantly limiting and impact reliability if there are unanticipated delays in new projects, unexpected retirements, or unanticipated load growth. These scenarios are monitored by the NYISO, and if any will happen, the NYISO will determine whether there will be a significant reliability impact. If the impact is imminent, the NYISO will request that the New York Transmission Owners (TOs) implement a Gap Solution under the CRPP. If there is a significant reliability impact to the system that will manifest itself during the next Comprehensive Reliability Planning Process (CRPP) cycle, the NYISO will address the issue in the next Reliability Needs Assessment.

Operational Issues (Known or Emerging)

No unusual operational issues have been identified for the period 2009–2018.

In the event of a catastrophic event on the New York system, the NYISO will conduct coordinated operations, and if necessary, coordinated restoration as presented in NPCC Regional Reliability Reference Directory 2, "Emergency Operations," and NPCC Regional Reliability Reference Directory 8, "System Restoration."

Reliability Assessment Analysis

[224] http://www.nyiso.com/public/products/icap/manuals.jsp

A. Comprehensive Reliability Plan (CRP)

The 2009 Reliability Needs Assessment (RNA) determined that there are no reliability needs anticipated through 2018. This outlook is an improvement from the findings of the 2008 RNA and results from an increase in generation additions and Special Case Resources (SCR) participation, along with a reduction in peak load forecast and planned retirements. As a result, the NYISO did not need to request market-based, regulated backstop, or alternative regulated solutions to meet the reliability needs over the ten-year horizon. The NYISO requested updates from the New York Transmission Owners/Operators (NYTOs) for incorporation into the 2009 (CRP) Base Case. On May 19, 2009 the NYISO issued the 2009 CRP, which set forth the assumptions, analysis, and resources on which BPS reliability will rely for 2009 to 2018, as discussed below.

While the 2009 CRP indicates the BPS will have sufficient resources to maintain reliability for the next ten years, if the implementation of planned resources included in the Base Case either does not occur at all or if certain scenarios analyzed in the RNA materialize, violations of the reliability criteria would result. This fact drives the need for vigilance in monitoring the conditions on the BPS as well as pending state and federal initiatives.

The 2009 CRP is based upon the resources and other key assumptions included in the 2009 RNA base case such as the peak load forecast, special case resources (SCR) forecast, generation additions, and scheduled unit retirements (see Table 4 below).

The peak load forecast used for the base case (35,658 MW) assumed the 2008 Gold Book econometric forecast adjusted for approximately 30 percent of the Energy Efficiency Portfolio Standard (EEPS) goals. The current economic recession was not reflected in the peak load forecast.

The SCR forecast assumed an increased SCR registration level in 2009 over the 2008 Gold Book level and this value was held constant over the ten-year study period.

Table 4 2008 RNA vs. 2009 RNA Load and Capacity)

	2008 RNA	2009 RNA	Delta MW
NYCA Load	37,631	35,658	(1,963)
SCR	1323	2084	761
Unit Additions	455	2169	1714
Unit Retirements	1428	1272	(1560)

Although the planned system meets the applicable reliability criteria based on the conditions studied, the 2009 RNA identified several scenarios that, if they were to occur, would adversely impact the effectiveness of the plan to meet future system reliability requirements.

The retirement of the Indian Point 2 and 3 nuclear power plant units would have the greatest and most immediate impact on the reliability of the New York Control Area (NYCA) system. In order to mitigate the impact of these retirements, approximately 1,000 MW of capacity would need to be installed in Southeastern New York (Zones G-K) for each retired unit. The total amount and location of the replacement capacity would depend upon the intra- and inter- area transmission limitations in the vicinity of the capacity additions. For the rest of the scenarios, the addition of 1,500 MW of new capacity installed in Southeastern New York would be sufficient to mitigate the adverse reliability impact.

The specific risk scenarios include:

- **Indian Point 2 and 3 Retirement** — Unexpected retirement of either of the two Indian Point nuclear plants at the expiration of their current operating licenses would cause immediate resource adequacy violations and the need for new resources in New York. The retirement of one of the two Indian Point nuclear power plant units (1,000 MW each) would cause an immediate violation of the reliability standard in 2014. Retirement of both units would cause a severe shortage in resources needed to maintain BPS reliability, resulting in the probability of an involuntary interruption of load that is approximately 40 times higher than the reliability standard in 2018.

- **Econometric Growth** — Forecasted econometric load growth level without EEPS impacts, which is 2,126 MW higher than the base case load forecast level in 2018, would result in the need for new resources in 2017. Under current economic conditions, surpassing the base case load forecast levels by 2,000 MW is unlikely.

- Environmental restrictions:

    - NOx Emissions — Implementation of new programs to control nitrogen oxides (NOx) emissions from fossil-fueled generators, such as the Ozone Transmission Commission (OTC) High Electric Demand Days (HEDD) program and Department of Environmental Conservation (DEC) new NOx Reasonably Available Control Technologies (RACT) program, could adversely impact the reliability of the electric system. Implementation of the OTC-HEDD Load Following Boilers (LFBs) and High Emitting Combustion Turbines (HECT) program could render some units unavailable and others limited to reduced output at times of peak energy needs, which would result in violations of the resource adequacy criterion in 2017 and 2018. The New York DEC is developing several proposals to lower emission limitations from generators in New York State. If such limitations are implemented without sufficient flexibility, under the new NOx RACT program, up to 3,125 MW of capacity may no longer be available to meet peak load conditions. If such conditions arise, and without any replacement resources, the resource adequacy criterion would be violated for all years from 2009 through 2018.

    - CO_2 Emissions, — With respect to the Regional Greenhouse Gas Initiative (RGGI) program, higher carbon allowance prices — combined with a reduced fuel price spread and other environmental program compliance costs — will place significant strain on whether, and the degree to which, fossil-fueled units particularly coal units, will be able to continue to operate. For example, as reflected in the 2009 RNA, allowance prices that reach or approximate the same levels as those being registered in the European market (e.g., at the time of the

2009 RNA issuance, \$35 to \$50/ton) will adversely affect the availability of allowances that are needed to operate facilities in New York. The latest RGGI auction was held December 17, 2008 and all 10 RGGI states participated. During the December auction all of the roughly 31.5 million CO_2 allowances were sold at a clearing price of \$3.38 per allowance. Additionally, RGGI future prices for December 2009 and December 2010 are currently trading in the \$3.50/ton to \$3.60/ton range. The RGGI market would be impacted by national cap and trade legislation, if enacted, as well as by the current economic recession.

- Clean Air Interstate Rule (CAIR) — There is a significant uncertainty about the long term impacts of CAIR on fossil generating units. In the near term, impacts are not expected to degrade reliability.

- **Zones at Risk —** An increase in load or a reduction in resources of 750 MW in the lower Hudson Valley or a change of between 500 and 750 MW in New York City in 2018 would cause reliability standard violations and a need for additional solutions. Similarly, removing 500 MW each from Zones G, H, and J would also cause a violation of the resource adequacy criterion and a need for additional solutions in 2018. The 2009 CRP base case will be a starting point for the NYISO's economic planning process, known as the Congestion Assessment and Resource Integration Study (CARIS). CARIS is an integral part of the NYISO's newly expanded planning process known as Comprehensive System Planning Process (CSPP). CARIS will evaluate transmission constraints and potential solutions to the congestion identified.

B. Installed Reserve Margin Study

The NYISO performs a resource adequacy study to help the New York State Reliability Council determine the required Installed Reserve Margin for the upcoming capability year. This study specifies the margin required for the New York Balancing Authority Area. The current level of the Installed Reserve Margin approved by FERC and the New York State Public Service Commission is 16.5 percent. The NYISO conducts a study to determine the Locational Capacity Requirement that must be fulfilled by load serving entities in the New York City and Long Island capacity zones. Reviewed by the NYISO's Operating Committee, that study 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 capacity totaling 97.5 percent of Long Island peak load be secured within that zone for the 2009–2010 capability years. The NYISO also performs an LOLE analysis that determines the maximum amount of ICAP contracts that can originate from BAs external to the New York Balancing Authority Area.

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 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 deliverability concerns in the IRM study 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.

Based upon the IRM and LCR the NYISO conducts semi-annual, monthly, and spot Installed Capacity (ICAP) auctions. Using the forecast load for 2009 and the 16.5 percent IRM, the NYISO calculated the ICAP requirement as 39,529 MW. Last year the IRM requirement was 15.0 percent. On February 6, 2009 the FERC issued an order accepting the New York State Reliability Council's filing of a 16.5 percent IRM for the State of New York. In addition to the generation resources within the New York Balancing Authority Area, generation resources external to New York can also participate in the NYISO ICAP market. An external ICAP supplier must declare the amount of generation accepted as ICAP in New York will not be sold elsewhere. The external BA in which the supplier is located has to agree 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 New York must be demonstrated to be deliverable to the New York border. The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to New York. Resources within the New York Balancing Authority Area that provide firm capacity to an entity external to New York are not qualified to participate in the NYISO ICAP market.

C. Other Analyses Affecting Resource Adequacy

Although deliverability of resources is evaluated in the NYISO's resource adequacy and planning studies both on an inter-area as well as intra-zonal basis, the NYISO currently has under development a deliverability test for new resources in its interconnection process. Resources that are not fully deliverable based on the test would either need to upgrade the system to be eligible for full capacity payments or only would be eligible to receive capacity payments for the portion of the facility that was deliverable.

NPCC requires that New York perform a comprehensive resource adequacy assessment every three years. This assessment utilizes 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.

Results of the most recent interim assessment[225] showed the NYCA would comply with the NPCC resource adequacy reliability criterion under the base load forecast. Under the High Load Forecast (5 percent probability of being exceeded), the NYCA would be in violation of the NPCC resource adequacy criterion in 2010 and 2011 if no further actions were taken. However, this assessment was based upon economic conditions forecasted prior to the economic decline experienced in the final quarter of 2008 and continuing into 2009. The 90/10 load forecasts published in the 2009 Gold Book for 2010 and 2011 are 1,039 and 1,199 MW less than those used in the interim assessment respectively.

[225] Interim Review of Resource Adequacy Covering the New York Control Area for the years 2009 to 2011 published October 2008. http://www.npcc.org/documents/reviews/Resource.aspx

The NYISO performs transient dynamics and voltage studies. There are no stability issues anticipated that could impact reliability during the 2009 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 UVLS.

The NYISO performs seasonal operating planning studies to calculate 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 Authority 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.

There is a potential for a natural gas shortage in New York State in the winter. This could cause natural gas fired units to burn other fuels or curtail operations. If unit operation curtailment due to fuel unavailability occurs in load pockets, generation from other areas would be needed to help meet demand, causing heavier loading on the existing transmission system. Many of the dual-fired units are the larger older steam units located in load pockets and would impact reliability needs in multiple ways if retired. The real challenge on a going-forward basis will be to maintain the benefits that fuel diversity (in particular dual-fired fuel capability,) provides today. This will be especially critical in New York City and Long Island which are entirely dependent on oil and gas fired units; many of which have interruptible gas transportation contracts. In terms of operational strategy, the NYSRC has adopted the following local reliability rule where a single gas facility refers to a pipeline or storage facility:

I-R3. Loss of Generator Gas Supply (New York City and Long Island)

"The NYS Bulk Power System shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City and Long Island zones."

The NYSIO categorizes generation capacity fuel types into three supply risks: low, moderate and high.

The greatest risk to fuel supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is approximately 9,000 MW greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000–26,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10 percent, there is sufficient generation in the low to moderate fuel risk categories to meet the winter electrical peak.

The New York Control Area also has a significant amount of Hydro resources. Many of these resources on located on rivers throughout the State. The output of these run-of-river resources are subject to water levels which may vary greatly on a month to month basis based upon weather conditions, snowfall amounts, temperature, rainfall amounts, etc. For reliability purposes these units are modeled with a 45 percent derate factor. This derate factor represents a severe scenario case for drought or low water level.

As stated previously, the 2009 CRP and 2009 RNA did not identify any reliability needs over the 10-year study period. The most current project schedules are also incorporated into the studies to reflect any potential changes due to economics, permitting, cancellations, etc. for resources expected to come on line during the study period. There are no current impacts to reliability due to economic conditions expected.

The NYISO monitors, on a quarterly basis, projects identified in an RNA assessment to determine that those projects remain on schedule. The NYISO also monitors progress on the state energy efficiency program implementation, SCR program registration, transmission owners' updated plans, and other planned projects on the BPS. Should the NYISO determine conditions have changed, it will determine whether market-based solutions that are currently progressing are sufficient to meet resource adequacy and the system security needs of the New York power grid. If not, the NYISO will address any newly identified reliability need in the subsequent RNA or, if necessary, issue a request for a Gap solution.

Should extreme conditions result in unanticipated load levels, the NYISO will call on its SCR and EDRP programs and invoke coordinated system operations through NPCC Regional Reliability Reference Directory 2, "Emergency Operations."

Other Region-specific issues that were not mentioned above

Region Description

NYISO formed as the successor to the New York Power Pool–a consortium of the eight investor-owned utilities, in 1999. The NYISO manages the New York State transmission grid encompassing approximately 10,892 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.2 million New Yorkers. New York experiences its peak load in the summer period with the current peak load of 33,939 MW in the summer of 2006. (http://www.nyiso.com).

Ontario

Demand

This year's demand forecast has an average annual growth rate of -0.7 percent over the period 2009–2018 compared to last year's average growth of -0.9 percent for the 2008–2017 timeframe. Although not as low, the growth profile is similar in that demand is expected to decrease, due to the impacts of conservation, embedded generation, and industrial restructuring. The change in growth rate is also a product of the much lower starting point. The current economic situation has brought forward some anticipated restructuring and has reduced some potential conservation savings.

Ontario's forecast of demand is based on monthly normal weather. The economic forecast is based on the most recent available information and predicts an economic trough later in 2009 with economic recovery in the last quarter of 2010. However, electricity demand is expected to lag the economic recovery. Structural change in Ontario's energy-intensive export industry will mean lower industrial demand for a number of years as the current economic environment will lead to a rationalization of inefficient or uncompetitive facilities. Conservation savings and the growth in embedded generation are expected to more than offset any growth from increased population and eventual economic recovery.

The forecast of Ontario peak demand is the system peak demand and therefore represents the coincident peak demand of Ontario's ten main sub-areas. All analysis is done on the system peak demand.

The Ontario Power Authority (OPA) is responsible for coordinating conservation programs throughout the province. To date, there are a number of initiatives that will reduce electricity demand. These programs range from lighting and refrigeration retrofits to new appliance standards. Measurement and verification will be the responsibility of the OPA as part of their mandate. Incremental conservation savings are expected to reach 4,000 MW over the forecast horizon.

Demand response within Ontario includes a number of different programs. Some wholesale customers within the province bid their load into the market and are responsive to price through IESO dispatch instructions. Other customers 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 currently amounts to slightly less than 1,000 MW in total, of which 60 percent is included for seasonal capacity planning purposes, with half of the included amount categorized as interruptible. This amount is expected to grow over time as more load is contracted to respond to tight supply conditions. By the end of the forecast, the interruptible component is expected to grow by more than 850 MW.

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. This is used with monthly normal weather demand to conduct probabilistic analysis. As well, the IESO uses an extreme weather scenario to study the impacts of adverse weather conditions on reliability of the IESO controlled grid. The IESO also reviews the reliability of the system prior to the impact of planned conservation savings. Although the IESO did not explicitly look at alternate economic scenarios, the preconservation results are considered as a surrogate for the potential to return to previous growth rates.

Generation

For summer 2009, the total capacity from existing installed resources connected to the IESO controlled grid is 33,637 MW, of which the amount of certain capacity is 28,010 MW. The remaining 5,627 MW is “uncertain” capacity, which includes on-peak resource deratings, planned outages, and transmission-limited resources. Over 2,300 MW of installed capacity was added to the system since last year’s assessment, with gas-fired generation making up approximately 2,000 MW of the new additions, and the balance comprising wind and hydroelectric generation. An additional 1,200 MW of dependable new supply (1,540 MW installed) is scheduled to come into service before the 2009 summer peak.

From 2009 to 2014, “certain” capacity from existing resources is expected to remain relatively constant. For the remainder of the forecast period (2015–2018), existing capacity is expected to decrease significantly. This decrease can be attributed to the planned retirement of all coal-fired generation by the end of 2014, as well as the anticipated retirement or refurbishment of several nuclear units. To manage the expected reduction in existing resources 7,800 MW of future capacity resources, as well as 4,400 MW of conceptual capacity resources, are scheduled to be in service by 2018. With the expected contribution of conservation programs administered by the OPA, and forecast increases in distributed generation, the combination of Existing, Future and Conceptual resources are expected to satisfy target Reserve Margins, ranging from 17.5 percent to 20.25 percent, throughout the forecast period.

As of spring 2009, the existing installed capacity of wind generation resources on the IESO controlled grid is 704 MW. Eleven percent of the installed wind capacity is assumed to be available at the time of summer peak, and 30 percent is assumed to be available at the time of winter peak. As a result, expected on-peak wind capacity for the summer and winter are 77 MW and 211 MW respectively. The seasonal capacity values for wind are calculated by taking the median wind capacity from historical wind output at selected seasonal peak hours. Both modeled (ten years of history) and actual (three years of history) wind data history is used. A conservative approach of taking the lower of the two (modeled or actual) capacity values for each season is applied. From 2011 onwards, the OPAs summer peak wind capacity value of 20 percent of installed capacity is used[226] (the winter capacity value of 30 percent is retained over this time period).

Solar capacity value is forecast to be 40 percent of installed for the summer peak and five percent of installed for the winter peak. These values are based on historical modeled photovoltaic output data at the time of summer and winter peaks.

No derate is forecast for biomass generation. It is assumed that the full installed capacity will be available at the time of the peak.

[226] Calculation of the OPA’s wind capacity contribution value can be found at the following link: http://www.powerauthority.on.ca/Storage/53/4871_D-5-1_Att_4_corrected_071019.pdf

The process used to select Future and Conceptual capacity resources is the OPA's working revision to the 2007 Integrated Power System Plan. Established in 2005, the OPA is the electricity system planner for the province of Ontario.

The OPA's statutory objects require it to ensure adequate, reliable, and secure electricity supply and resources in Ontario and to conduct independent planning for electricity generation, demand management, conservation, and transmission.

One of the responsibilities of the OPA is to develop a 20-year Integrated Power System Plan (IPSP) and to submit the IPSP to the Ontario Energy Board for its review and approval. The IPSP is to be updated every three years. The IPSP must follow any directives issued by Ontario's Minister of Energy and Infrastructure relating to the government's electricity goals. In addition, the OPA must develop appropriate procurement processes for managing electricity supply, transmission capacity, and demand measures and must apply to the Ontario Energy Board for approval of the IPSP's proposed procurement processes.

Ontario's first IPSP was submitted to the Ontario Energy Board for review in August 2007. It covers a period of 20 years, complies with the goals and requirements set out by the government of Ontario, and proposes a procurement process for managing electricity supply, transmission capacity, and demand measures. In the fall of 2008, Ontario's Minister of Energy and Infrastructure directed the OPA to revisit the IPSP with the aim of establishing new targets for the amount and diversity of renewable energy sources, conservation programs and other initiatives.

In September 2009 the provincial government passed the Green Energy and Green Economy Act (GEA) providing a comprehensive framework for developing renewable energy generation. This framework includes a feed-in tariff program and provisions that will facilitate the implementation of the necessary transmission and distribution infrastructure to support those renewable projects.

Capacity Transactions on Peak

At present, there are no Firm, Expected or Provisional purchases to or from other Regions.

The IESO has agreements in place with neighboring jurisdictions in NPCC, RFC, and MRO for emergency imports and reserve sharing, should they be required in day-to-day operations.

Transmission

The 1250 MW interconnection between Hawthorne Transformer Station (TS) in Ontario and the Outaouais station in Québec is scheduled to be in-service in the summer of 2009. This project consists of a 230 kV double circuit line between Hawthorne TS and the Outaouais station, with back-to-back HVdc converters at the Outaouais station. This project will also result in improvements to the local network in the Ottawa Area, enhancing its load-meeting capability.

To coincide with the completion of the new interconnection, the existing special protection system (SPS) at St. Lawrence, which initiates the rejection of generation capacity at Saunders Generating Station (GS) in response to contingencies involving the circuits between eastern Ontario and the Toronto area, is being enhanced. These enhancements will increase not only the scope of the SPS's coverage but also the range of responses available for various contingency conditions. The SPS will increase the allowable imports that can be accommodated simultaneously via the interconnections between Hydro Québec and New York.

Phase-angle regulators are currently installed on three of the four Michigan to Ontario interconnections. One phase angle regulator, on the Keith to Waterman 230 kV circuit J5D has been in service and regulating since 1975.

The other two available phase-angle regulators, on circuits L51D and L4D, are currently bypassed during normal operations, but are available for use during emergency operations. They will become operational once agreements between the IESO, the Midwest ISO, Hydro One, and the International Transmission Company are finalized. The operation of the phase angle regulators will assist in the control of circulating flows. The fourth phase-angle regulator(s) (2 phase angle regulators in parallel), which is responsible for controlling the tie flow on the 230 kV circuit B3N, is scheduled for replacement in 2010 (However, replacement could be complete by the end of 2009.). The replacement phase-angle regulators will be located in Michigan at the Bunce Creek terminal of the B3N circuit.

Construction of a new 176 km (110 mile) 500 kV double-circuit line from the Bruce Complex to Milton Switching Station (SS) is scheduled to commence this summer, with completion expected before the end of 2011. This new line is required to accommodate the output of all eight generating units at the Bruce Complex together with approximately 700 MW of existing and committed wind-generating capacity, as well as a further 1,000 MW of new renewable generating capacity that is forecasted for development within the unit. With the new generating facilities, the combined transfer from the Bruce Complex is projected to total approximately 8,100 MW.

The existing Bruce SPS is also to be enhanced not only to accommodate the two new 500 kV circuits between the Bruce Complex and Milton TS, but also to address other contingency conditions not presently covered by the SPS. The intent of the expanded coverage is to limit the extent of restrictions imposed on the output from the Bruce units during outage conditions while also assisting with the re-preparation of the system following a permanent fault when subsequent contingency conditions may become more critical.

Since the current version of the Bruce SPS has now been in-service for over 16 years and some of the equipment has been superseded by more advanced technology, a project has been initiated by Hydro One to replace the existing facilities. The replacement SPS, which is scheduled to be in-service by mid-2012, is to include the NPCC Type II functionality required for extreme contingencies specifically the loss of multiple circuits on the Bruce to Milton right-of-way.

To accommodate the new Darlington B nuclear generating station, construction of a 46 km (28.8 mile) long 500 kV double-circuit line between Bowmanville SS and Cherrywood TS will be required. The Government of Ontario announced in June that it is suspending the RFP process to procure two nuclear reactors planned for the Darlington site.

The plan for the new 500 kV line also includes the development of the 500/230 kV Oshawa Area TS, approximately 20 km (12.5 miles) west of Bowmanville SS on the proposed double circuit line. This new TS will then supply the local area load, reducing the transfers through the four 750 MVA auto-transformers at Cherrywood TS.

The completion of the two new gas-fired generating facilities in the Sarnia Area has added approximately 1,700 MW of capacity in the area and is expected to results in constraints on the transmission system between the Sarnia and London Areas. Following the planned retirement of the Lambton coal-fired generation station by 2014, these constraints are expected to diminish or be eliminated, particularly with low levels of imports from Michigan.

However, should it be decided to develop additional renewable or combined heat and power generating capacity in southwestern Ontario then, depending on the amount, these constraints would re-emerge requiring consideration to be given to reinforcing the transmission system west of London. Depending on the amount of new generating capacity to be incorporated, these transmission facilities will be designed for operation at either 230 kV or 500 kV. Should it be decided to install 500 kV facilities, then 500/230 kV auto-transformers will also be required at Lambton TS and possibly at Chatham TS.

A number of major transmission reinforcement projects are being planned for in-service between the 2012 to 2018 time frame. Many of them are required for enabling renewable generation developments across Ontario. The major new transmission projects that have been identified include:

- a 500 kV line(s) between Sudbury and Toronto
- a 500 kV line between Sudbury and the Mississagi station east of Sault Ste. Marie
- a 230 kV line between Nipigon and Wawa along the East-West Tie
- a 230 kV line between Wawa and Mississagi station
- a 230 kV line north of Thunder Bay in northwestern Ontario
- a 230 kV line between the St Lawrence station (Cornwall) and Ottawa

The need and timing of these projects are contingent on the uptake and location of the generation projects that are procured under the proposed Feed-In Tariff Program or through other means. At this time, the OPA, the IESO Hydro One and other transmitters will initiate the development work to minimize the lead-time required to bring these facilities to service.

Further to the major transmission projects, local transmission upgrades shown below are also needed to facilitate renewable generation developments. The implementation of these projects will depend on the resource development interest.

- Bruce peninsula, along its Lake Huron shoreline — enabler lines terminating at Owen Sound TS and at Seaforth TS
- Parry Sound Area, along the Georgian Bay shoreline — enabler line terminating at Parry Sound TS
- North Bay Area, along the Lake Nipissing shoreline — enabler line terminating at North Bay TS
- Area west of Thunder Bay — enabler line terminating at Lakehead TS
- Manitoulin Island — enabler line terminating at new connection point near Espanola TS

- Area north of Nipigon TS along the shoreline of Lake Nipigon — enabler line terminating at a new connection point near Nipigon TS
- Wanstead Area — enabler line terminating at a new connection point on circuits N21W/N22W
- Pembroke Area — enabler line terminating at Arnprior TS

Measures to address the concerns identified in some of the large load centers regarding supply security, as well as the ability to restore the supply following an interruption, are also being developed. Proposals include the development of either new generation facilities or a new 230 kV connection into the Cambridge Area; the installation of 230/115 kV auto-transformers in the Guelph Area; the installation of generation capacity in the south-western portion of the Greater Toronto Area; and the installation of generation capacity in northern York Region.

The transmission projects that are under various stages of construction and the planned projects will address the transmission constraints identified. The transmitters in Ontario together with the OPA proactively plan the transmission network in order to ensure timely system adjustments, upgrades, and expansions.

To coincide with the completion of the new Bruce to Milton 500 kV line, a 350 Mvar SVC is to be installed at Nanticoke SS, connected to the 500 kV busbar, and another 350 Mvar SVC is to be installed at Detweiler TS, connected to the 230 kV busbar. These SVCs are required to provide dynamic reactive support following a critical contingency involving either of the 500 kV circuits between the Bruce Complex and Milton TS.

During the second half of this year approximately 1,700 Mvar of 230 kV connected shunt capacitor banks are to be installed at Nanticoke SS, Middleport TS, and Buchanan TS. Although these capacitor banks are required primarily to provide reactive support following the scheduled shut-down in 2014 of the generating facilities at Nanticoke GS, they are also an integral component of the measures required during the interim period prior to the completion of the new Bruce to Milton 500 kV line. With Units 1 and 2 at the Bruce Complex scheduled to return to service during 2010 there will be periods during 2010 and 2011 when either seven or eight Bruce units will be available for service. During these periods of high loading on the existing transmission circuits, reactive power management plays a significant role in reducing generation constraints. During the interim period, prior to the new line being completed, the new shunt capacitor banks will allow as much of the reactive capability from each of the operational units at Nanticoke SS to remain available for post-contingency voltage support. Once the new line is in service, the shunt capacitor banks together with new SVCs are required to support the post-contingency transfers without the need for generation rejection.

During the second half of 2010, series capacitors are to be installed at Nobel TS, the approximate mid-point of the two 500 kV circuits between Hanmer TS (Sudbury) and Essa TS (Barrie). To complement these series capacitors, a 300/-100 Mvar SVC is to be installed at Porcupine TS (Timmins) and a 200/-100 Mvar SVC is to be installed at Kirkland Lake TS. Together, these facilities will increase the transfer capability of the Flow-South Interface from 1,300 MW to approximately 2,100 MW. This increase will be sufficient to relieve the existing congestion on this interface, while also accommodating the additional output from the proposed expansion of the four existing hydroelectric stations on the Lower Mattagami River (approximately 435 MW) together with other committed renewable energy developments in north-eastern Ontario.

Operational Issues (Known or Emerging)

As noted in last year's assessment, plans for the retirement of all coal-fired generation by the end of 2014 are well underway. In the years following the coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. Ontario government directives call for the amount of planned nuclear capacity to be limited to 14,000 MW over the next 20 years. To meet this objective, the majority of nuclear units will need to be refurbished or replaced through new-build projects. Post-2015, decisions and timelines regarding the retirement or refurbishment of existing nuclear units will require a sophisticated outage management program to ensure an adequate level of resources and operational flexibility. As discussed in the transmission section above, careful management of the transmission system with respect to outages and new transmission capability will also be required.

Although energy supplies available within Ontario are expected to be adequate overall, energy deficiencies could arise as a result of prolonged extreme weather conditions and environmental restrictions. Interconnection capability and available market and operational measures have been evaluated as adequate to ensure summer energy demands can be met for a wide variety of conditions. The IESO uses a measure of forecast uncertainty in a probabilistic analysis to account for variations in demand due to weather volatility. This uncertainty is used in conjunction with the normal weather demand forecast to determine resource adequacy. As well, the IESO creates a demand forecast based on extreme weather and uses it in further assessing system adequacy.

Ontario is currently benefiting from improved resource adequacy levels, due in part to new supply coming in-service as existing coal-fired facilities remain operable. Anticipated future and conceptual supply resources and a lower demand forecast (due to conservation targets, increased distributed generation, and a restructuring economy) has Ontario well positioned for the phase-out of coal-fired generation by the end of 2014. This has enabled the Ontario government to implement greenhouse gas emissions limits for coal-powered generation starting this year. Emission targets are as follows: 19.6 megatons (Mt) in 2009, 15.6 Mt in 2010, and a hard cap of 11.5 Mt by 2011. For 2009, Ontario's coal-fired generation operator, Ontario Power Generation, in cooperation with the IESO implemented a program to meet emissions targets while limiting reliability impacts. All coal-fired capacity remains available to meet summer and winter peak demand periods. Similar programs are being evaluated for 2010 and beyond to meet emissions targets while maintaining overall system reliability.

The integration of variable resources (wind, solar, etc.) is a top priority as Ontario moves towards a higher penetration of renewable resources. Wind capacity connected to the bulk power transmission system is expected to exceed 1,500 MW by 2012, while the potential to further increase the amount of wind supply in the province is significant. The IESO has identified that at higher wind penetration levels, heightened attention would be required for the system to be able to handle the variability of wind generation. As a result, the IESO is exploring opportunities to implement a centralized wind forecast to facilitate the real-time operation of the power system.

The expansion of renewable generation within Ontario's distribution systems is expected to increase significantly over the next ten years. The OPA is managing contracts for over 1,400 MW of renewable generation connected to the distribution system to be in place by 2011. It is expected that distributed generation will soon displace significant amounts of output from larger generating units that are connected to the high-voltage transmission system. These large units currently provide fast voltage control, operating reserve, and load as a contribution to the reliability of the grid. The IESO is assessing all of these aspects and are actively engaged with stakeholders to develop the capabilities to maintain the reliability of the grid, as the types and characteristics of the future supply mix changes. The IESO is also working with local distribution companies, the OPA, and the Ontario Energy Board (OEB) to increase visibility of the real-time output of distributed generation in an effective manner.

In early spring 2009, the Ontario system experienced extended periods of Surplus Baseload Generation (SBG). SBG is an over-generation condition that occurs when electricity production from Ontario's baseload and intermittent facilities (nuclear, must-run hydroelectric, wind, etc.) exceeds demand; and typically occurs during the low demand periods such as overnight, weekends, and holidays. With expected increases to some types of baseload generation (e.g., wind), and a lower forecast for demand, management of SBG conditions in Ontario is a top priority for the IESO. These periods are currently being managed through market exports, nuclear dispatch, and hydroelectric spill. If these actions prove insufficient the IESO has the authority to intervene further with wind generation curtailment and baseload unit shutdowns.

Ontario is not currently experiencing low water-drought conditions. Forecast hydroelectric output is based on the median historical values of hydroelectric production and contribution to operating reserve during the weekday peak hours. Actual hydro production values are compared to these forecasted values on a monthly basis. The median hydroelectric value assumed available for annual peak is about 75 percent of the total installed capacity.

Reliability Assessment Analysis

IESO reliability assessments include multi-area resource adequacy modeling and transmission adequacy assessments that are conducted to determine the deliverability of resources to load. Assessment criteria and processes are described in the documents "Methodology to Perform Long-Term Assessments"[227] and "Ontario Resource and Transmission Assessment Criteria."[228]

From these assessments, two major reports are periodically published by the IESO:

- 18-Month Outlook
- Ontario Reliability Outlook

Every quarter the IESO prepares an 18-Month Outlook, which advises market participants of the resource and transmission reliability of the Ontario electricity system. Specifically, the Outlook assesses potentially adverse conditions that may be avoided through adjustment or coordination of generation and transmission maintenance schedules. In addition, the Outlook reports on initiatives that are being put in place to improve reliability over the 18-month forecast timeframe.

[227] http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp
[228] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

At least once a year, the IESO investigates the adequacy of the Ontario system for the next five years. The key messages stemming from this adequacy assessment are published in the Ontario Reliability Outlook.

The IESO determines required reserve levels based on probabilistic methods deemed by NPCC to be acceptable for meeting Regional LOLE criteria. The target Reserve Margin levels range from 17.5 percent in 2009 to 20.25 percent in 2018. In considering what resources contribute to adequacy the IESO assumes that future and conceptual resource additions can meet their stated in service dates, and the forecast amount of conservation and embedded generation envisioned by the OPA can be achieved.

Each year, in compliance with NPCC and Ontario 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. In addition, the IESO participates with other members of NPCC in Regional studies that assess the Regional long-range adequacy and interconnection benefits between Balancing Authorities in NPCC. Similar transmission assessments are carried out; these are referenced below.

At this time, the reserve requirements are met solely with existing, future and conceptual resources that are internal to Ontario. Should capacity commitments be contracted in future from external entities, these will be included in Ontario studies. During supply shortage conditions, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC, and MRO contain contractual provisions for emergency imports directly by the IESO. Ontario also has access to Regional reserve sharing for operating reserve activation under contingency situations.

Projected Reserve Margin requirements are determined on the basis of the IESO's requirement for Ontario self-sufficiency. At least once a year the IESO assesses resource requirements for the next five years (short-term period). In association with the OPA, Reserve Margin requirements for the long term (years six to ten) are determined and resource plans are developed, as part of the IPSP process. Transmission assessments for specific projects are conducted on an as-needed basis, as far into the future as necessary, recognizing the long lead time for significant transmission facility development. In addition, a review of the transmission system over the next five-year period is conducted annually to ensure continued adherence with NPCC Criteria. A comprehensive review is also required to be undertaken at least every five years. These reviews are useful in identifying possible future deficiencies in the transmission system.

IESO and the Ontario Power Authority recognize the potential for certain adverse conditions to result in higher-than-expected resource unavailability and establish planning reserves sufficient to handle many of these conditions. To the extent resource procurement exceeds the planning reserve requirements, resource adequacy can be maintained for higher-than-normal contingencies. However, there are always conditions, which can exceed those planning assumptions. In such adverse situations the IESO's operations would rely on interconnection support and available control actions to maintain system reliability. Through retention and further development of a diverse resource mix, the potential consequence of these events is reduced.

IESO assessments of resource adequacy recognize the supply limitations associated with uncertain and transmission constrained resources. Transmission limits are modeled on a zonal basis and recognize transmission improvements, which will result from implementation of the OPA's IPSP. Uncertain resources, such as wind, are considered using a statistical approach, which conservatively combines simulated and historical data to arrive at expected levels of "certain" capability.

In May 2009, the Ontario government passed the Green Energy and Green Economy Act aimed at facilitating the large scale development of renewable energy projects across Ontario. Included in the Act is provision for a Feed-in Tariff (FIT), which is designed to encourage greater renewable development, with greater geographic distribution than currently exists with large grid-connected generation complexes. The IESO continues to track the progress of renewable energy projects in Ontario, and is streamlining its processes to incorporate additional renewable projects in the future. For assessment purposes, variable generation such as wind and solar are treated as capacity resources with discounted capacity values based on historical output at the time of seasonal peak demand (see generation section for detailed description).

Demand response programs in Ontario are treated as a supply resource with discounted capacities associated with the unique characteristics of each program (e.g., voluntary/firm contracts). The OPA manages contracts for the majority of the Demand Response programs scheduled to come into service over the forecast timeframe. Programs with firm contracts to reduce demand during periods of high demand and tight supply are expected to provide a reliable and verifiable supply resource.

A number of major unit refurbishment or retirement decisions are expected to occur in Ontario throughout the assessment timeframe. Expected unit retirements are approximately 6,400 MW of coal-fired resources across four facilities and 15 units (by the end of the year 2014). In addition, as described in the operability section, a number of existing nuclear units are scheduled for retirement, or alternatively, refurbishment starting in 2015.

Measures taken to mitigate reliability concerns include the development of an IPSP for Ontario. The IPSP considers expected and potential unit refurbishments or retirements and proposes ways to meet resulting resource requirements. Specific measures include the procurement of new gas-fired units, renewable resources, and conservation programs as well as the procurement of refurbished nuclear resources. In addition, the IPSP considers the potential role for nuclear refurbishments and new-build nuclear resources as well as transmission that would be required to integrate all of the above-mentioned resources. Other options include the potential for firm purchases from outside of Ontario, expanding capability at existing gas-fired stations, continuation of capability at existing gas-fired stations that would otherwise be retired, developing greater coordination and flexibility related to nuclear refurbishment outages, and converting existing coal stations to alternate fuels. Mitigation of reliability concerns is to be supported through ongoing monitoring, assessment, measurement, verification, and regular updates (i.e., every three years) to the IPSP.

The IESO has a local-area deliverability criterion for load security and restoration, and a resource-adequacy assessment criterion, which are described in sections 7 and 8 of the "Ontario

Resource and Transmission Adequacy Criteria”[229] document. In the quarterly and annual assessments mentioned at the beginning of the section, the IESO identifies any deliverability concerns which are subsequently addressed by the transmitters as part of their planning activities and the OPA as part of the generation procurement programs.

There are currently no UVLS systems installed in Ontario for the purpose of controlling the voltage on the BPS portion of the IESO-controlled grid in response to contingencies. There are several systems used for localized voltage control in the event of an outage to local supply facilities.

Following the 1998 ice storm and prior to the 2002 opening of Ontario s competitive markets for electricity, Ontario’s Emergency Planning Task Force (EPTF) was created. It is chaired by the IESO and includes the major electricity sector players including the provincial government’s Ministry of Energy. The EPTF oversees an emergency management team, the Crisis Management Support Team (CMST), to manage and mitigate the impact on public health and safety due to an extended electricity system emergency. Annually Ontario runs a program of Reliability and Emergency Management workshops including table top drills. Additionally major integrated exercises are staged in which both the operational response and emergency management infrastructure is activated. The CMST also performs regular test activations.

During the nine-day capacity and energy emergency that followed the August 2003 blackout, the CMST managed the emergency via 31 conference call meetings and were instrumental in producing media messages, facilitating the government's appeal and direction for reduced demand, and obtaining of environmental variances for additional supply.

A previous reliability concern in Ontario centered on the loss of 500/230 kV transformer capability in the Toronto area under high-load conditions. This has been mitigated by local generation development, moderated demand levels, and an autotransformer replacement program to improve the replacement timing should an autotransformer fail. In particular, the major transmitter in Ontario maintains at least one 750 MVA 500/230 kV autotransformer at their central storage at any given time. The transmitter also has access to lightly-loaded auto transformers in other parts of the system in an emergency.

In 2008, the IESO conducted an Interim Review of Transmission Adequacy which assessed the IESO controlled grid’s conformance with the NERC TPL-001 –004 standards and NPCC’s more stringent planning criteria. The Ontario power system, including the proposed generation and transmission changes up to 2012, is in conformance with the applicable NPCC criteria and NERC standards, with no exceptions. The proposed changes and additions to the existing power system in Ontario will not adversely affect the reliability of the Eastern Interconnection.

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

[229] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

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.

In 2008 the IESO initiated the Ontario Smart Grid Forum, a broad-based industry working group focused on developing a vision for a provincial Smart Grid that will provide consumers with more efficient, responsive, and cost-effective electricity service. A report on the key findings and recommendations of the forum was released in early 2009[230]. The report highlighted the ongoing development of Smart Grid-related activities occurring both in Ontario and around the world; and provided a list of key recommendations for further development of the Ontario Smart Grid. The province's plan for all utilities to equip their residential and small business customers with a smart meter by 2010 (Ontario's Smart Metering Initiative) is well underway, and remains an integral part of this development.

Other projects aimed at improving BPS reliability include the IESO's development of an on-line limit derivation tool to maximize transmission capability in the operating time frame. This tool is planned to be implemented in stages over the next four years.

The reliability impacts due to aging equipment are managed by the equipment owners through extensive maintenance programs and equipment replacement programs for equipment that is expected to reach end of life. The IESO facilitates these replacements through an expedited connection assessment and approval process.

Although significant impacts of the economic recession have been observed in demand levels, there is no indication that any generation or transmission projects have been deferred or cancelled as a result of the current economic climate.

Region Description

The province of Ontario covers an area of 1,000,000 square kilometers (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.

[230] http://www.ieso.ca/imoweb/pubs/smart_grid/Smart_Grid_Forum-Report.pdf

Québec Interconnection

Introduction

The Québec BA's NERC *2009 Long-Term Reliability Assessment Reference Case* is identical to the Scenario Case (for the NERC *2009 Scenario Reliability Assessment*, a report that accompanies this report)[231] with renewable resources integration. This is because all future resources to be placed in service are renewable (Hydro, wind and biomass power).

Hydro-Québec is the main generator, transmission provider and load-serving entity in Québec. Its only shareholder is the Québec government. It mostly uses renewable generating options — particularly hydropower — and supports wind energy development as a logical complement to hydro power through purchases from independent power producers in Québec. Hydro-Québec has an interest in other renewable sources such as biomass, geothermal, and solar energy. Hydro Québec also contributes to research on new generating options such as hydrokinetic power, salinity gradient power and deep geothermal energy. It also conducts research in energy-related fields such as energy efficiency.

Hydro-Québec is one of the largest power producers in North America. Close to 94 percent of the generation capacity is hydroelectric. Generally, hydroelectric projects must meet three criteria before they can proceed: they must be profitable, environmentally acceptable, and favourably received by host communities.

All electricity generation methods have environmental impacts. One way to limit these impacts is to control demand. Hydro-Québec works closely with the "*Agence de l'efficacité énergétique*" (Energy Efficiency Agency) to encourage customers to use energy more wisely, as part of its Energy Efficiency Plan.[232]

Hydro-Québec reiterates its commitment to sustainable development by focusing on renewable energy. New resources to be put on line will be renewable resources (wind, biomass, and hydropower). Therefore, the Scenario Case (renewable resources integration scenario) is identical to the *NERC Long-Term Reliability Assessment 2009 Reference Case*.

Compared to the *NERC Long-Term Reliability Assessment 2008 Reference Case* there are five new items in this assessment:

- Call for tenders A/O 2009-02 for two blocks of 250 MW of wind-generated capacity, one resulting from First nations projects and one resulting from community projects. An English description of this call for tenders can be found at this web address: http://www.hydroquebec.com/distribution/en/marchequebecois/ao-200902/index.html;

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

[232] With a focus on sustainable development, the Agence de l'efficacité énergétique's mission is to promote energy efficiency and the development of new technologies for all forms of energy in every sector of activity. Its English web site address is: http://www.aee.gouv.qc.ca/en/home/.

- Call for tenders A/O 2009-01 for 125 MW of biomass cogeneration. An English description of the call for tenders can be found at this web address: http://www.hydroquebec.com/distribution/en/marchequebecois/ao-200901/index.html;
- Power Purchase Program for small hydropower projects of 50 MW or less for a total of 150 MW. To be released later in 2009;
- Wind project (280 MW) by Hydro-Québec Production;
- New energy efficiency programs evaluated at 1,150 MW.

The last Québec Area Comprehensive Review of Resources Adequacy, approved by the Reliability Coordinating Committee of the NPCC on March 11, 2009, indicates the long-term required reserve margin, expressed as a percentage of the total load forecast, should be around 12 percent in order to meet the NPCC reliability criterion of a maximum 0.1 day per year of LOLE. This comprehensive review is available on the NPCC web site: http://www.npcc.org/documents/reviews/Resource.aspx.

Significant assumptions

NERC requires each BA area to produce a scenario which accommodates a minimum of 15 percent of total energy from renewable resources, with no more than 5 percent made up from energy efficiency programs. The base year for calculating the 15 percent benchmark is 2008. These renewable resources should be put in service within 10 years.

In 2008, the internal demand in Québec was 188,918 GWh. Fifteen percent of this internal demand represents 29,106 GWh. Therefore, the area has to integrate almost 30 TWh per year of renewable resources to its electric system within 10 years.

The Québec BA area already has 532 MW of wind-power generation, and during the next 10 years 3,450 MW of additional wind-power generation will come on line. In all its previous reliability studies, Québec's wind generation was derated to zero. In this assessment, this is still the case. By the end of 2009, Hydro-Québec Distribution will present its analysis regarding the Québec wind farms' capacity factor on peak to the Québec Energy Board. A capacity factor of 30 percent is expected to used in future studies.

Demand

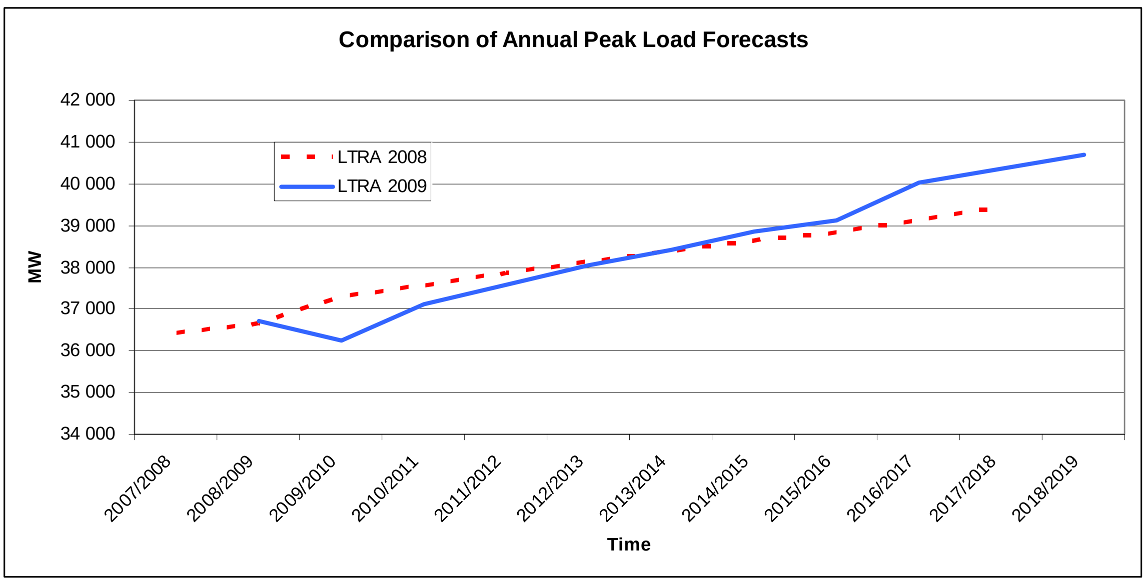
There is no difference between the load forecasts used in this 15 percent renewable resource integration scenario case and the reference case of the NERC *2009 Long-Term Reliability Assessment.*

The observed peak load for winter 2008/2009 was 37,230 MW and was reached on January 16, 2009 at 8 a.m.. This is a new all-time record for internal demand in Québec. Demand was approximately 850 MW higher than the forecast peak for winter. This is due to a short but sharp cold spell, culminating on January 16. Montréal temperature at the time of peak was -26°C (-11°F) and wind speed was about 11 km/hour (7 mph). The rest of winter 2008/2009 experienced close to normal temperatures and internal demand values were also close to projected values. The available internal capacity (with due regard to imports, exports and demand response programs) was sufficient to balance out the load with all operating reserves well within limits.

Climatic uncertainty is modeled by recreating each hour of the 36 year period (1971 through 2006) under the current load forecast conditions. Moreover, each year of historic data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend for example. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of those 252 scenarios. A high-case demand scenario is also produced. Economic parameters are set higher and the same method used to create the base case is reproduced. For the first year of forecasting, the high case scenario is two to three percent higher than the base case scenario. Modeling uncertainty is represented through load multipliers covering two standard deviations. Each load multiplier has a certain probability of occurrence. Given the global uncertainty and assuming a normal distribution, the peak demand standard deviation is 1,710 MW for the 2009/10 Winter Operating Period.

The average annual *2009 Long-Term Reliability Assessment* Québec load forecast growth, from the winter peak period 2008/2009 to 2018/2019, is 1.04 percent. Hydro-Québec Distribution is the only LSE in Québec. Its load forecast is conducted for the Québec Balancing Authority Area represented as a single entity and there is no demand aggregating.

The Québec area peak information is coincident. Resources evaluations are based on coincident winter peak forecasts, with base case and high case scenarios.



Under Hydro-Québec's Energy Efficiency Plan (EEP), the goal for 2010 is 5.8 TWh in recurring energy savings. The target for 2015 incorporating all of initiatives is 11 TWh/year. The EEP focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers.

The programs and tools for promoting energy saving are the following:

For residential customers

- Energy Wise home diagnostics
- Recyc-Frigo (old refrigerator recycling)
- Electronic thermostats
- Energy Star qualified appliances
- Lighting
- Pool-filter timers
- Energy Star windows and patio doors
- Rénoclimat renovating grant
- Geothermal energy

For business customers — small and medium power users

- Empower program for buildings optimization
- Empower program for industrial systems
- Efficient products program
- Traffic light optimization program
- Energy Wise diagnostic

For business customers — large power users

- Building initiatives program
- Industrial analysis and demonstration program
- Plant retrofit program
- Industrial initiatives program

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

Generation

In Québec, all the resources to be put on line are renewable resources (wind power, biomass, and hydroelectric power). Therefore, the renewable resources integration scenario is identical to the *NERC 2009 Long-Term Reliability Assessment*.

In order to go ahead, hydroelectric development projects must fulfill three criteria. They must be:

- profitable;
- environmentally acceptable;
- favorably received by the host communities.

Hydropower facilities with reservoirs offer unique operational flexibility in that they can respond immediately to fluctuating demand for electricity. Hydropower's flexibility and storage capacity make it the most efficient and cost-effective way to support the deployment of intermittent renewable resources such as wind power. Wind is variable, partly unpredictable and is impossible to store. Alone, it cannot ensure electrical service at the exact time consumer needs are felt. Integration of wind energy involves the use of supply sides resources to serve load not served by wind generation and to maintain bulk power supply security. Wind power is then combined with other electricity generating resources. They must be brought on line according to wind availability and must be flexible so output can be quickly adjusted to wind generation. Hydroelectric generating stations have an edge over thermal technology because of their very short start up/shutdown times, and their capability of performing load following and load-frequency control on the grid.

Renewable Resources Integration Scenario - 15% of Québec Internal Demand (in MW).

Supply	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
Wind I - 990 MW	128	150	560	671	671	671	671	671	671	671
Wind II - 2 000 MW	0	0	475	1,059	1,331	1,781	2,055	2,055	2,055	2,055
Wind III - 500 MW	0	0	0	100	300	500	500	500	500	500
Wind - HQP - 280 MW	212	437	437	437	437	437	437	437	437	437
Total Wind Power	**340**	**587**	**1,471**	**2,266**	**2,738**	**3,388**	**3,662**	**3,662**	**3,662**	**3,662**
Biomass (125 MW)	**0**	**0**	**0**	**0**	**125**	**125**	**125**	**125**	**125**	**125**
Small Hydro - 150 MW	0	0	0	25	50	100	150	150	150	150
EM-1 A - Hydro			0	533	768	768	768	768	768	768
La Sarcelle - Hydro			0	100	150	150	150	150	150	150
Rupert Diversion - Hydro		0	0	0	0	0	0	0	0	0
Complexe de la Romaine - Hydro				0	0	622	622	882	1,260	1,260
Private Production - 70 MW - Hydro	0	35	70	70	70	70	70	70	70	70
Total Hydro	**0**	**35**	**70**	**728**	**1,038**	**1,710**	**1,760**	**2,020**	**2,398**	**2,398**
Energy Efficiency - New Programs	**170**	**340**	**500**	**700**	**880**	**1010**	**1150**	**1150**	**1150**	**1,150**
Total Supply	**510**	**962**	**2,041**	**3,694**	**4,781**	**6,233**	**6,697**	**6,957**	**7,335**	**7,335**

Hydro-Québec considers hydroelectricity to be a highly flexible, clean, and renewable basic form of energy. Wind power is not a substitute for hydroelectricity, but is viewed as a complement.

Hydro-Québec cooperates with Environment Canada in conducting studies to characterize and forecast wind power generation in order to maximize output from this energy source without adversely affecting transmission grid reliability. Hydro-Québec is continuously developing management tools for balancing hydro and wind power, as well as wind turbine and wind farms behaviour simulation models.

Based on the last Hydro-Québec Distribution Procurement Plan filed with the Québec Energy Board in November 2008, Hydro-Québec Production's investment plan along with different Québec governmental decrees, it is shown that the Québec Balancing Authority area creates a scenario with more than 19 percent of renewable resources.

In 2008, Québec's internal energy consumption was 188,918 GWh. This internal demand doesn't include 5,123 GWh of load reduction due to energy efficiency programs. Therefore, Québec's internal consumption was 194,041 GWh in 2008 (see Table 1).

Table 1 - Renewable Resources Integration Scenario - 15% of Québec Internal Demand (in GWh).

Load	2008-Actual	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Québec Internal Demand [1,2]	188,918	186,617	187,479	190,627	193,720	195,366	197,206	199,200	203,873	207,520	209,155
Energy Efficiency											
- 1990's Programs	2,200	2,100	2,100	2,000	2,000	1,900	1,900	1,900	1,800	1,800	1,800
- New Programs	2,923	3,928	4,815	5,821	6,902	8,135	9,632	11,323	11,822	11,822	11822
Québec Internal Demand	**194,041**	**192,645**	**194,394**	**198,448**	**202,622**	**205,401**	**208,738**	**212,423**	**217,495**	**221,142**	**222,777**
15 % of Québec Internal Dema	29,106										

[1] : March 2009 Revision Forecast;
[2] : Québec Internal Load Forecast doesn't includes energy efficiency programs.

Supply	1	2	3	4	5	6	7	8	9	10
Wind I - 990 MW	391	460	1,715	2,056	2,056	2,056	2,056	2,056	2,056	2,056
Wind II - 2 000 MW	0	0	100	1,600	3,300	4,600	5,400	6,300	6,300	6,300
Wind III - 500 MW	0	0	0	0	400	1,000	1,600	1,600	1,600	1,600
Wind - HQP - 280 MW	650	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340
Total Wind Power	**1,041**	**1,800**	**3,155**	**4,996**	**7,096**	**8,996**	**10,396**	**11,296**	**11,296**	**11,296**
Biomass (125 MW)	**0**	**0**	**0**	**100**	**900**	**900**	**900**	**900**	**900**	**900**
Small Hydro - 150 MW	0	0	0	200	300	600	800	800	800	800
EM-1 A - Hydro			950	2,320	2,320	2,320	2,320	2,320	2,320	2,320
La Sarcelle - Hydro			60	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Rupert River Diversion - Hydro		6,000	6,000	5,332	5,332	5,332	5,332	5,332	5,332	5,332
Complexe de la Romaine - Hydro				0	0	690	2,970	2,970	3,580	6,040
Private Production - 70 MW - Hydro	20	254	536	536	536	536	536	536	536	536
Total Hydro	**20**	**6,254**	**7,546**	**9,388**	**9,488**	**10,478**	**12,958**	**12,958**	**13,568**	**16,028**
Marginal Energy Efficiency Programs	**1,005**	**1,892**	**2,898**	**3,979**	**5,212**	**6,709**	**8,400**	**8,899**	**8,899**	**8,899**
Total Supply	**2,066**	**9,946**	**13,599**	**18,463**	**22,696**	**27,083**	**32,654**	**34,053**	**34,663**	**37,123**
					Total Supply as % of Québec Internal Demand:					19.1%
					Energy Effiency as % of Québec Internal Demand:					4.6%

Table 2

PLANNED RESOURCES in MW [1]

Call for Tenders - Wind I	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
- St-Ulric - St-Léandre	127.5	150	150	150	150	150	150	150	150	150
- Les Méchins			150	150	150	150	150	150	150	150
- Mont-Louis		100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5
- Montagne-Sèche			58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5
- Gros-Morne 1			110.5	110.5	110.5	110.5	110.5	110.5	110.5	110.5
- Gros-Morne 2				111	111	111	111	111	111	111

Call for Tenders - Wind II	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
- Des Moulins			156	156	156	156	156	156	156	156
- St-Rémi				100	100	100	100	100	100	100
- St-Valentin				50	50	50	50	50	50	50
- De l'Érable			100	100	100	100	100	100	100	100
- Massif du Sud				150	150	150	150	150	150	150
- Seigneurie de Beaupré 2					132.6	132.6	132.6	132.6	132.6	132.6
- Seigneurie de Beaupré 3					139.6	139.6	139.6	139.6	139.6	139.6
- Clermont							74	74	74	74
- Rivière du Moulin Ph 1						150	150	150	150	150
- Rivière du Moulin Ph 2							200	200	200	200
- Ste-Luce				68	68	68	68	68	68	68
- Lac Alfred Ph 1				150	150	150	150	150	150	150
- Lac Alfred Ph 2					150	150	150	150	150	150
- New Richmond				66	66	66	66	66	66	66
- Le Plateau			138.6	138.6	138.6	138.6	138.6	138.6	138.6	138.6
- Aguanish			80	80	80	80	80	80	80	80
- MRC la Matépédia						100	100	100	100	100

Call for Tenders - Wind III	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
- 2 X 250 MW				100	300	500	500	500	500	500

Call for Tenders - Biomass II				125	125	125	125	125	125	125
Call for Tenders - Small Hydro			25	50	100	150	150	150	150	150

Hydro-Québec Production	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
- Eastmain-1 A			533	768	768	768	768	768	768	768
- La Sarcelle			100	150	150	150	150	150	150	150
- La Romaine Complex						622	622	882	1260	1260

Private Producers - Small Hydro	35	70	70	70	70	70	70	70	70	70

[1] : For Wind Power, the In-Service dates are December 1st of the indicated year and for hydro and Biomass Power, the In-Service dates are November 1st of the undicated year.

Eastmain-1 A/Sarcelle/Rupert Project

The project consists of building a 768 MW generating station — Eastmain-1 A powerhouse — near the existing Eastmain-1 powerhouse, and diverting part of the flow of the Rupert River into these two facilities, then through Sarcelle powerhouse and on to Robert-Bourassa (LG-2), La Grande-2-A and La Grande-1 generating stations.

The Rupert diversion will involve the following structures and facilities:

- four dams.
- a spillway on the Rupert River, which will also function as an instream flow release structure.
- 74 dikes.
- two diversion bays (forebay and tailbay) with a total area of about 346 km^2 at maximum operating level.
- a 2.9 km long tunnel between the Rupert forebay and tailbay.
- a network of canals with a total length of about 12 km to facilitate flow in the various portions of the diversion bays.
- Hydraulic structures on the Rupert River to maintain post-diversion water levels along approximately 48 percent of the river's entire length.

The project, scheduled for commissioning in 2011–2012, will give Hydro-Québec's generating fleet an additional capacity of 918 MW and an additional output of 8.5 TWh per year, distributed as follows:

- additional output at Eastmain-1-A and Eastmain-1 powerhouses: 2.3 TWh.
- output at La Sarcelle powerhouse: 0.9 TWh.
- additional output at Robert-Bourassa, La Grande-2-A and La Grande-1 generating stations: 5.3 TWh.

Information regarding this project can be found on the following Web sites:

- http://www.hydroquebec.com/rupert/en/index.html
- http://www.hydroquebec.com/eastmain1/en/batir/resume.html

Romaine Complex

Hydro-Québec Production has obtained the necessary approvals to build a 1,550 MW hydroelectric complex on the Rivière Romaine, on the lower north shore of the St-Lawrence River. The complex will consist of four hydro generating stations with an annual output of 8.0 TWh. Construction has begun in March of 2009 and is scheduled to be completed in 2020. The first Romaine commissioning is planned for 2014. Project information, in English, is available on the following Web site :
http://www.hydroquebec.com/romaine/pdf/2009G133_la_romaine_en.pdf

Capacity Transactions on Peak

Québec has a 200 MW firm purchase contract with New Brunswick until October 2011.

There are two firm export contracts. One is with Ontario — 145 MW until 2018; and the other is with New England — 310 MW until the end of 2011.

Hydro-Québec Distribution includes, when planning its resources, a potential of 1,000 MW of interconnection assistance for winter months (mainly from the state of New York). When needed, short term calls for tenders are launched and transmission capacity is reserved for those short term purchases. Hydro-Québec Production can participate in theses calls for tenders.

Transmission

In 2009 TransÉnergie has commissioned a new two-line 625 MW back-to-back HVdc interconnection with IESO in the Ottawa-Gatineau Area across the Ottawa River (The Outaouais Interconnection). This station is integrated into the 315 kV double-circuit existing line from Chénier in the Montréal Area to Vignan in the Gatineau Area. The Ontario side of the station is a 240 kV section integrating a double-circuit 240 kV line from Hawthorne substation in Ottawa.

In 2010, a new 315 kV double-circuit line between Chénier and Outaouais and a fourth 735/315-kV transformer will be added to permit full use of the interconnection.

The following table shows the transmission line additions through this report's horizon.

Transmission Project Name From / To	Voltage (KV)	Length (Miles)	In-Service Date(s)
Les Méchins / Line 23 XY	230	6,3	Dec-2009
Goemon / Mont-Louis	230	46,3	Dec-2010
Goemon / Gros Morne	315	55,6	Dec-2011
Chénier / Outaouais	315	70,6	May-2010
Eastmain-1A / Eastmain-1	315	1,2	July-2010
Sarcelle / Eastmain-1	315	68,8	July-2010
Romaine-2 / Arnaud	315	162,9	Dec-2014
Romaine-1 / Romaine-2	315	19,1	Dec-2016
St-Ulric- Saint-Léandre line	230	3,7	Dec-2009
Rimouski-Les Boules line	230	39,1	July-2009
Les Méchins wind farm line	230	2,5	Dec-2011
Montagne Sèche wind farm line	161	22,4	Dec-2011
Des Moulins wind farm line	230	1,9	Dec-2011
Lac Alfred wind farm line	315	17,4	Dec-2013
De L'Érable wind farm line	120	9,3	Dec-2011
Massif du Sud wind farm line	120	12,4	Dec-2012
St-Rémi wind farm line	120	0,3	Dec-2012
Vents-du-Kempt wind farm line	120	5,7	Dec-2014
St-Robert-Bellarmin wind farm line	120	16,1	Dec-2011
New Richmond wind farm line	230	5,0	Dec-2012
Ste-Luce wind farm line	230	0,3	Dec-2012
Clermont wind farm line	315	5,7	Dec-2015
Lac Alfred wind farm line	315	18,0	Dec-2012
Le Plateau wind farm line	315	0,1	Dec-2011
Seigneurie de Beaupré wind farm line	315	14,3	Dec-2013
Rivière-du-Moulin wind farm line	345	18,6	Dec-2014

Information regarding these transmission projects can be founded on the following Web sites:

- http://www.hydroquebec.com/projects/integration_parcs_eoliens_1.html
- http://www.hydroquebec.com/projects/integration_parcs_eoliens_2.html
- http://www.hydroquebec.com/projects/sarcelle_eastmain_1.html
- http://www.hydroquebec.com/projects/romaine_transport.html
- http://www.hydroquebec.com/projects/pdf/montagne-decision.pdf
- http://www.hydroquebec.com/projects/pdf/lac_alfred.pdf
- http://www.hydroquebec.com/projects/pdf/goemon-decision-avril-2009.pdf
- http://www.hydroquebec.com/projects/pdf/rimouski_200804.pdf

In addition to the equipment required to connect the wind plants to the transmission network, a number of transmission reinforcements are necessary in order to respect thermal limits. Moreover, to enable reliable and secure integration of wind farms to the transmission system, system design criteria and technical requirements must be met. Wind plants should achieve a performance comparable to conventional power plants (equipped with synchronous generators):

- Under and over-voltage ride-through capability;
- Voltage reduction capability (reactive power);
- Frequency regulation capability (active power);

- Under and over-frequency ride-through capability.

The geography of the Québec Balancing Authority Area is such that the system consists of two major branches – one emanating from the La Grande Generation Complex (Western branch) and the other emanating from Churchill-Falls and the Manicouagan-Outardes Generation Complex (Eastern branch). These branches join in the southern part of the system where the major load centers are situated. The distance between these large generation complexes and the load centers are in the order of 700 to 800 miles.

TransÉnergie, the Transmission Operator, operates an extensive transmission system in order to provide the necessary access to resources and to loads. The following table shows the main load-end substations and associated transmission to be built during the study horizon.

Transmission Project Name From / To	Voltage (KV)	Length (Miles)	In-Service Date(s)
In Progress - New Installations			
Mont-Tremblant station	120-25 kV		Dec-2009
and Line	120	4.8	Dec-2009
Vaudreuil-Soulanges station	120-25 kV		Nov-2009
In Progress - Restorations			
Delson station	120		Nov-2009
Saint-Basile station	120		Nov-2010
Sorel Station	120		Nov-2010
Planned - New Installations			
Anne- Hébert station	315-25 kV		Fall 2010
and Line	315	8.2	Fall 2010
Beauceville - Sainte-Marie	120	18.6	Spring 2011
Montcalm station	230-25 kV		2012
Neubois station	120-25 kV		Fall 2012

No delay is expected however, in the event delays occur the reliability of the BPS will not be affected.

Operational Issues

There are no significant anticipated unit outages, variable resources, transmission outages, or temporary operating measures anticipated to impact reliability during the next 10 years.

One major anticipated unit outage (Gentilly-2 nuclear unit of 675 MW) is scheduled from late 2010 to mid-2012; this outage will not impact reliability. Variable resources, transmission additions, and temporary operating measures are not expected to negatively impact reliability during the next ten years.

Non-hydraulic resources account only for a small portion of total resources. Plants using oil or jet fuel are refuelled by boat or truck and generally not during the winter season. Natural gas is used at a single cogeneration plant and is delivered under a firm natural gas purchase contract.

Operational planning studies are being continuously conducted by TransÉnergie, the Québec area controller. Yearly peak-demand period studies are conducted to assess system conditions during winter-peak periods. Extreme weather in Québec translates into very low temperatures during the winter operating period. Through a transmission planning criterion, transmission planning studies must take into account a 4,000 MW load increase above the normal load forecast on the system during such extreme weather conditions. This is equivalent to 110 percent of system peak load. Québec relies on both internal and external resources to serve this additional load and transmission capacity is available.

Reliability Assessment Analysis

To determine whether existing and planned resources provide an adequate level of reliability, Québec uses the NPCC resource adequacy criterion, an LOLE of 0.1 day per year. Last Québec area Comprehensive Review of Resource Adequacy, approved by the NPCC Reliability Coordination Committee (RCC) in March 2009 (http://www.npcc.org/documents/reviews/Resource.aspx), indicates that a long-term required reserve of 11.7 percent of the peak load is needed. This percentage can vary if future resources have different characteristics or the load uncertainty varies. The Québec area treats short-term (i.e., 1–4 years) and long-term (5 years and more) reserve margins requirements slightly different. The long term required reserve is equal to the fourth year of the assessment. This four-year time frame gives sufficient time to build new peaking units or to find new demand side resources.

As shown in the next table, until 2015/2016, the Québec area has surplus resources. For the last three years of this assessment, additional resources are needed to respect the NPCC reliability criterion (750 MW in 2016/2017, 850 MW in 2017/2018, and 1,200 MW in 2018/2019). At that time, Québec will have close to 4,000 MW of wind power as installed capacity. In this assessment of reliability wind power is derated to zero. If a capacity factor of 30 percent was used to assess reliability, wind power represents an equivalent peak capacity of 1,200 MW and reserve margins would be within target.

Demand, Resources and Reserves (in MW)

YEAR	Net Internal Demand (A)	Deliverable Capacity Resources (B)	Planned Reserves (C = B-A)	Planned Reserves % (D = C/A)
2009/2010	34,500	40,182	5,682	16.5%
2010/2011	35,353	40,190	4,837	13.7%
2011/2012	35,826	40,013	4,187	11.7%
2012/2013	36,313	41,402	5,089	14.0%
2013/2014	36,672	41,452	4,780	13.0%
2014/2015	37,391	42,124	4,733	12.7%
2015/2016	37,675	42,108	4,433	11.8%
2016/2017	38,570	42,331	3,761	9.8%
2017/2018	39,000	42,709	3,709	9.5%
2018/2019	39,306	42,709	3,403	8.7%

Hydro-Québec's energy requirements are mostly met by hydro generating stations, which are located on different river systems scattered over a large territory. The major plants are backed by multi-year reservoirs (water reserves lasting more than one year). The Québec Balancing Authority Area can rely on those multi-year reservoirs and on some other non-hydraulic sources, including fossil generation, allowing it to cope with inflow variations.

Hydro-Québec Production's hydro generating units can be classified into three categories: run-of-river units, annual reservoir and multi-annual reservoir hydro generating units. Each category copes with low water inflows in a different way:

- Run-of-river units: relatively constant hydraulic restrictions from year to year.
- Annual reservoir hydro units: during a year with normal water inflows, these reservoirs are almost full at the beginning of the winter. If annual water inflow is low, hydraulic restrictions increase.
- Multi-annual reservoir hydro units: the target level for multi-annual reservoirs is approximately 50 to 60 percent full in order to compensate or store inflows during periods of below-or above-normal water inflows. Hydraulic restrictions increase during a period of low inflows.

After a severe drought (having a two percent probability of occurrence) the hydro generation on the system would suffer additional hydraulic restrictions of about 500 MW above the normal condition restrictions. Stream flows, storage levels and snow cover are constantly monitored allowing Hydro-Québec Production plan a margin to cope with drought periods.

To assess its energy reliability, Hydro-Québec developed an energy criterion that states that sufficient resources should be available to run through sequences of two or four years of low inflows, having a two percent probability of occurrence. Hydro-Québec must demonstrate its ability to meet this criterion three times a year to the Québec Energy Board. The last assessment can be found on the Québec Energy Board Web site:
http://www.regie-energie.qc.ca/audiences/Suivis/Suivi-D-2008-133_Criteres/HQD_R-3648-2007_Annexes_Suivi_D2008-133_3juin09.pdf.

To smooth out the effects of a low inflow cycle, different means are identified:

- reduction of the energy stock in reservoirs to a minimum of 10 TWh at the beginning of May.
- external non-firm energy sales reductions.
- production of thermal generating units during an extended period of time.
- purchases from neighboring areas.

Other Region-Specific Issues

Hydro-Québec considers hydropower (small and large) as a renewable resource. The U.S. Department of Energy (DOE) in a number of publications has made several references to hydropower as a renewable resource:

> "Water is currently the leading renewable energy source used by electric utilities to generate electric power. The major advantage is that water is a source of cheap power.

In addition, because there is no fuel combustion, there is little air pollution in comparison with fossil fuel plants and limited thermal pollution compared with nuclear plants." http://www.eia.doe.gov/cneaf/solar.renewables/page/hydroelec/hydroelec.html

"Hydropower relies on the water cycle, which is driven by the sun, thus it's a renewable power source." http://www1.eere.energy.gov/windandhydro/hydro_ad.html

"The DOE program conducts research to improve two renewable energy technologies: hydropower and wind energy."http://www1.eere.energy.gov/windandhydro/program_Areas.html

"Competitive Electric Power from Renewable Energy

- About 10 percent of U.S. electricity comes from hydropower;
- More than 75 percent of the nation's renewable energy is generated by hydropower." http://www1.eere.energy.gov/windandhydro/about.html

"Hydropower is using water to power machinery or make electricity. Water constantly moves through a vast global cycle, evaporating from lakes and oceans, forming clouds, precipitating as rain or snow, and then flowing back down to the ocean. The energy of this water cycle, which is driven by the sun, can be tapped to produce electricity. Hydropower uses a fuel – water – that is not reduced or used up in the process. Because the water cycle is an endless, constantly recharging system, hydropower is considered a renewable energy." http://www1.eere.energy.gov/windandhydro/hydro_how.html

"The 2002 United Nations World Summit on Sustainable Development identified all hydro as a renewable source of energy to be supported by the international community." http://www.hydropower.org/downloads/F4%percent20Hydropower%percent20Making%percent20a%percent20Significant%percent20Contribution%percent20Worldwide.pdf

Region 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 January 2009 was 41,689 MW, of which 38,953 MW (93.4 percent) was hydroelectric capacity. There are more than 140 generating stations on the Québec electric system.

The transmission voltages on the Québec's system are 735, 315, 230, 161, and 120 kV. Transmission line length totals about 33,060 km (20,540 miles).

The Québec electric system 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 neighboring systems.

The population served is around 7 million and the Québec area covers about 1,668,000 km^2 (643,848 square miles). Most of the population is grouped 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.

About This Report

Background

The *2009 Long-Term Reliability Assessment* represents NERC's independent judgment of the reliability of the BPS in North America for the coming ten years (Table Report 1).[233] The report specifically provides a high-level reliability assessment of the 2009 to 2018 seasonal resource adequacy and operating reliability, an overview of projected electricity demand growth, Regional highlights, and Regional self-assessments.

Table Report 1: 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 BPS and to make recommendations for their remedy as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations and exchange vital system reliability information. This assessment is prepared by NERC in its capacity as the Electric Reliability Organization.[234] 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.[235] 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 Long-Term Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The Resources Issue Subcommittee (RIS) and Transmission Issues Subcommittee (TIS) also contributed to the report by providing input on emerging issues. The report is based on data and information submitted by each of the eight Regional Entities in May 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 and validation on the reference information received from the Regions, as well as review of all self-assessments to form its independent view and assessment of the reliability of the coming ten years. NERC also uses an active peer review

---

[233] 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.

[234] 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."

[235] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

process in developing reliability assessments. The peer review process takes full advantage of industry subject-matter expertise from many sectors of the industry. This process also provides an essential check and balance for ensuring the validity of the information provided by the Regional Entities.

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 Trustees (BOT) approval, considering comments from the OC. The entire document, including the Regional self-assessments and the NERC independent assessment, 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 Long-Term Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[236]

- Supply and demand projections are based on industry forecasts submitted in May 2009. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting timeframe (May – August).
- 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 dispatchable and controllable Demand Response programs will yield the forecast results, if they are called on.
- Other peak demand-side management programs, such as Energy Efficiency and price-responsive Demand Response, are reflected in the forecasts of net internal demand.

[236] 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).

2009 to 2018 Long Term Reliability Assessment Data Request
The data request letter provided to Regional Mangers on November 26, 2008 included the following instructions:

Regional Self Assessment — 2009 Long Term Reliability Assessment
Prepare a written assessment for your Region discussing any situations that could affect reliability for the next ten years — the write-up should be submitted in Microsoft Word format, following the ***Reliability Assessment Narrative Format-Guide,*** attached separately**.** To improve the consistent look and feel of the report, *please do not copy and paste tables/charts from other reports, rather re-develop these materials ensuring the suggested templates are followed.*

Each Region is requested to include the specific information covered in the sections below. If your Regional self-assessments are divided into subregions, the subregion assessments should address each of these sections and questions individually, with the overall Regional self-assessment providing a high-level overview. Consistent responses representing all subregions can be provided at the Regional level.

All regions must follow the outline below in preparing their written assessment.

Executive Summary

Provide a one or two paragraph executive summary of the expected Regional performance over the next ten years.

Introduction

Introduce the Region and high-level results. Then proceed to provide your self assessment along with responding to the questions below.

Please organize your self-assessment into the following template. Your self-assessment should respond to the following questions:

1. Demand

a) Compare last year's compound annual growth rate for 2008–2017 to this year's 2009–2018 ten-year assessment timeframe for your 50/50 forecast, and present the key factors leading to any significant changes in the forecast.

b) Discuss weather and economic assumptions upon which the 2009–2018, 50/50 demand forecast is based.

c) What method is used to aggregate total internal peak demands of individual member's actual loads for use in the forecast? Separately:

   i. Discuss if the Region/subregion peak information is coincident or non-coincident. Discuss which peak condition your Region/subregion(s) base their resource evaluations.

   ii. Specify and describe the current and projected energy efficiency programs. Review measurement and verification programs used for energy efficiency.

   iii. Specify and describe the current and projected Demand Response programs that reduce peak demand — i.e., interruptible demand; direct control load management; critical peak pricing with control; load as a capacity resource, etc. Review measurement and verification programs used for Demand Response.

d) Describe the Regional or subregional quantitative analyses evaluating the potential variability in projected demand due to weather, economic, or other key factors.

2. Generation

a) Identify the amount of Existing (Certain, Other and Inoperable), Future, and Conceptual capacity resources (See data forms and instructions for enhanced capacity definitions) during the study period. Identify the portions (MW) that are:

   i) Variable (i.e., wind, solar, etc.) capacity expected on peak and the maximum capacity from the variable plants. Discuss how capacity values are calculated in your Regions/subregions.

   ii) Biomass (wood, wood waste, municipal solid waste, landfill gas, ethanol, and other biomass).[237]

b) For Future and Conceptual capacity resources, identify the process used to select resources for reliability analysis/Capacity Margin calculations (i.e., forward capacity markets, obligation to serve activities, etc.). Quantify this resource selection and allocations if possible.

3. Capacity Transactions on Peak

a) Imports on Peak

   i) Identify and quantify imports from other Regions and those imports between your subregions that are part of their Capacity Margins. Categorize them as:

      i. Firm — contract signed.
      ii. Expected — no contract executed, but in negotiation, projected, or other.
      iii. Provisional — transactions under study, but negotiations have not begun.

   ii) What portion of the imports is backed by firm contracts for both generation (contract tied to specific generator) and transmission? Clarify if import assumptions are based on partial path reservations.

b) Exports on Peak

   i) Identify and quantify exports to other Regions and those exports between your subregions that are part of their Capacity Margins. Categorize them as:

      i. Firm — contract signed.
      ii. Expected — no contract executed, but in negotiation, projected, or other.
      iii. Provisional — transactions under study, but negotiations have not begun.

   ii) What portion of the exports is backed by firm contracts for both generation (contract tied to specific generator) and transmission? Clarify if export assumptions are based on partial path reservations.

[237] Defined by EIA as: *"organic nonfossil material of biological origin constituting a renewable energy source."*

4. Transmission

Describe any BPS transmission categorized as under construction, planned or conceptual (see data instruction sheets) anticipated in-service during the ten-year study period. Are there any concerns in meeting target in-service dates of this transmission? If so, could the delay impact BPS reliability and how are these concerns being addressed?

a) Does the Region/subregion have any transmission constraints that could significantly impact reliability and what are the plans to address these constraints?

b) Provide a table, sorted by subregion, of significant transmission additions required to support bulk power reliability under this scenario:

Transmission Project Name	Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status

c) Provide a table, sorted by subregion, of significant transformer additions required to support bulk power reliability under this scenario:

Transformer Project Name	High-Side Voltage (kV)	Low Side Voltage (kV)	In-service Date(s)	Description/Status

d) Provide a listing of any other significant substation equipment (i.e., SVC, FACTS controllers, HVdc, etc.)

5. Operational Issues (Known or Emerging)

a) Are there any anticipated generating unit/transmission outages and/or temporary operating measures that may impact reliability during the next ten years?

b) Discuss operational measures available if peak demands are higher than expected due to weather or other conditions. For this analysis, use 90/10 forecast demands where available, an approximation if 90/10 forecasts are not available or an extreme, historical weather condition.

c) Are there either environmental or regulatory restrictions that could potentially impact reliability? If so, please explain, including the projected magnitude (in MW) of the restriction and its impact on operational margins.

d) Describe any operational changes resulting from integration of variable resources (i.e., wind, solar, etc.)?

e) Are there operational changes or concerns resulting from distributed resource integration (i.e., significant amounts of generation connected to the distribution system, etc.)?

f) Are there low-water levels or high-water temperature concerns in your Region? Discuss Regional/subregional plans to mitigate their affects to meet Capacity Margin needs.

6. Reliability Assessment Analysis

Describe the assessment process used by the Region and subregions. ***(Cite reports documenting studies in footnotes or reference).***

a) Identify the projected Capacity Margins and compare them to the Regional, subregional, state, or provincial requirements.

- i) What assumptions were used to establish the Regional/subregional Capacity Margin criteria, target margin level or resource adequacy levels (i.e., Loss-Of-Load Expectation, Expected Unserved Energy, etc.)?
- ii) Describe the latest resource adequacy studies (i.e., Loss-of-Load Expectation, Expected Unserved Energy, etc.).
- iii) What is the amount of resources internal and external to the Region or subregion that are relied on to meet the target margin level, or forecast load for the assessment period?[238]
- iv) Describe any reliance of the Region or subregions on emergency imports, reserve sharing or outside assistance/external resources (clarify whether it is external to the subregion or the Region), where these resources are expected to come from and coordination with other Regions which may also require these same resources.
- v) Does the Region/subregion treat short-term (i.e., 1–5 years) and long-term (i.e., 6–10) Capacity Margins requirements differently? If so, describe.
- vi) Discuss any significant changes from last year's assessment, including demand forecasts, major new capacity, and bulk transmission projected to be in service during the next ten years.
- vii) Discuss resource adequacy if fuel interruptions or other conditions such as extended drought or forced outages are experienced.
- viii) Describe how energy-only and transmission-limited resources are considered in your resource adequacy assessment.
- ix) For variable renewable resources, discuss/describe
  - (i) Renewable Portfolio Standards (RPS) or other mandates that impact your resource adequacy process. Review.
  - (ii) How variable resources are considered (i.e., wind, solar, etc.) in your resource adequacy assessment.
  - (iii) Planning approaches/changes developed to ensure reliable integration and operation of variable resources.

[238] Each Region/subregion may have their own specific margin level (or method) 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 Margin Level. If not, NERC will assign a 13 percent Reference Margin Level for predominately thermal systems and 9 percent for predominately hydro systems

x) Discuss how you consider demand response in resource adequacy assessment. Discuss planning approaches/changes used to ensure reliable operation.

b) Identify unit retirements which have significant impact on reliability. What measures have you taken to mitigate the reliability concern?

c) Describe the latest generation deliverability (both internal and external) studies performed.

i) Explain and reference documentation, and provide the definition of deliverability used in your Region/subregion. Explain how the Region/subregion ensures resources are sufficient and deliverable to meet load requirements during system peak.

ii) If any deliverability concerns are identified, explain what mitigation procedures are in place to address them.

iii) What analysis is done to ensure that external resources needed are available and deliverable on-peak?

iv) What major transmission additions are required to support the addition of new resources or imports, especially in the 6–10 year time period? Emphasize transmission elements that have a long lead time.

d) Do you expect to install more Under Voltage Load-Shedding (UVLS) in your Region/subregion? How much load (MW) is targeted by UVLS to protect against BPS cascading events and how does this influence your reliability assessment?

e) Describe the Region/subregion planning process for catastrophic events: for example, the loss of a fleet of generators due to earthquakes, hurricanes, major pipeline or fuel disruption, or loss of a major import path.

f) Does the Region/subregion have plans for dealing with a drought or low water conditions? If so, explain how you have included the reliability impacts in the next few years. What is the reduction in projected total capacity (hydro, fossil, and nuclear). How the Region/subregion intends to meet the capacity/Reserve Margin requirements.

g) Does your Region or subregion have guidelines for on-site, spare generator step-up (GSU) and auto transformers? If yes, please briefly describe the guideline. Does your Region or subregion participate in any program to share spare transformers?

h) Describe the TPL-001 — TPL-004 operational planning studies performed by your Regional Entity's participants, what reliability issues were identified and what are the plans to address them. In addition:

i. Describe any dynamic and static reactive power-limited areas on the BPS in your Region/subregion and plans to mitigate them.

ii. Do you have criteria for voltage stability margin in your Region/subregion? If yes, state the criteria and explain how it is being applied to meet the peak summer conditions.[239]

i) What new technologies, systems, and/or tools does the Region expect to deploy to improve BPS reliability (i.e., "Smart Grids," FACTS, etc.)?

j) Are there any reliability impacts due to aging infrastructure? If so, what mitigation programs have been implemented?

k) Are there any impacts on reliability (i.e., project slow-downs, deferrals, cancellations, etc.) resulting from the economic conditions in your Region/subregion?

7. Other Region-specific issues that were not mentioned above?

Discuss what the Region is doing to minimize any other anticipated reliability concerns during the next ten years.

8. Region Description

List the number of members, balancing authorities, and other organizations (associate members, for instance) in the Region. State the season in which the Region typically experiences its peak demand, the number of square miles in the Region, the states that comprise the Region and the approximate total population served.

[239] ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/Survey-of-the-Voltage-Collapse-Phenomenon-Optimized.pdf

Enhancements to the *2009 Long-Term 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.

A number of the task force's recommendations[240] were incorporated into the *2009 Long-Term Reliability Assessment*, including:

1. The Reliability Assessment Guidebook Task Force released its *Reliability Assessment Guidebook* (Version 1.2),[241] 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 quality, 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 addition to applying a stringent data-checking process, third-party data validation evaluations were implemented to compare industry forecasts against third-party model outputs.
4. In order to broaden stakeholder input, OC involvement was incorporated to support the assessment development and approval process.
5. Supply categories have been enhanced for 2009 to better assess capacity availability and identify certainty of future various capacity resources. Notably, this assessment uses the following supply categories: "Existing, Certain,", "Existing, Other" and "Existing, but Inoperable." Future capacity is categorized as "Future, Planned", "Future, Other", and "Conceptual". Definitions to these terms are provided in the *Terms Used in this Report* section.
6. "Reserve Margin" replaces "Capacity Margin" used in the *2008 Long-Term Reliability 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.
7. New and more granular data on existing and planned transmission was gathered. The transmission threshold of 200 kV and above was reduced to 100 kV and above to address all BPS transmission. Additionally, projected transmission lines in this assessment are categorized using the following structure: "Existing", "Under Construction", "Planned" and "Conceptual. Definitions to these terms are provided in the *Terms Used in this Report* section.
8. A Long-Term Scenario Assessment, to be published as a supplemental report, will provide insights on the impacts of significant changes in system characteristics and reliability.

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

Report Content Responsibility

In close collaboration with NERC staff, the RAS oversees the preparation of the seasonal and Long-Term Reliability Assessments. The RAS reports to the PC and its members prepare the Regional data and narratives, conduct peer reviews, develop Emerging Issues, and contribute to the report writing and review process. The following NERC industry groups have also collaborated efforts to produce NERC's *2009 Long-Term Reliability Assessment*:

NERC Group	Relationship	Contribution
Board of Trustees	NERC's Independent Board of Trustees	• Review the *2009 Long-Term Reliability Assessment* • Approve for publication
Planning Committee (PC)	Reports to NERC's Board of Trustees	• Review *2009 Long-Term Reliability Assessment* • Risk assessment of Emerging/Standing Issues
Operating Committee (OC)	Reports to NERC's Board of Trustees	• Review Assessment and provide comments to PC on operational aspects
Energy Ventures Analysis, Inc.	Third-Party Independent Consultant	• Provide assessment on North American natural gas, coal, and uranium conditions
Integration of Variable Generation Task Force (IVGTF)	Reports to the PC and OC	• Contribute to Standing Issues
Load Forecasting Working Group (LFWG)	Reports to RAS	• Develop load forecasting bandwidths
Data Coordination Working Group (DCWG)	Report to Data Coordination Subcommittee	• Develop data and Regional reliability requests • Data checking and validation
Eastern Interconnection Reliability Assessment Group (ERAG)	Independent Reliability Group	• Contributed to demand data validation effort
Reliability Impacts of Climate Change Initiatives Task Force (RICCITF)	Reports to the PC and OC	• Contribute to Standing Issues
Reliability Metrics Working Group (RMWG)	Reports to the PC	• Reviewed the ALR Metrics
Resource Issues Subcommittee (RIS)	Reports to PC	• Develop Emerging Issues • Demand resources
Transmission Issues Subcommittee (TIS)	Reports to PC	• Develop Emerging Issues

Reliability Concepts Used in This Report

How NERC Defines Bulk Power System Reliability
NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects[242]:

> **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 LSE via contract or agreement for curtailment.[243]
- 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.

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.

---

[242] 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).

[243] 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.

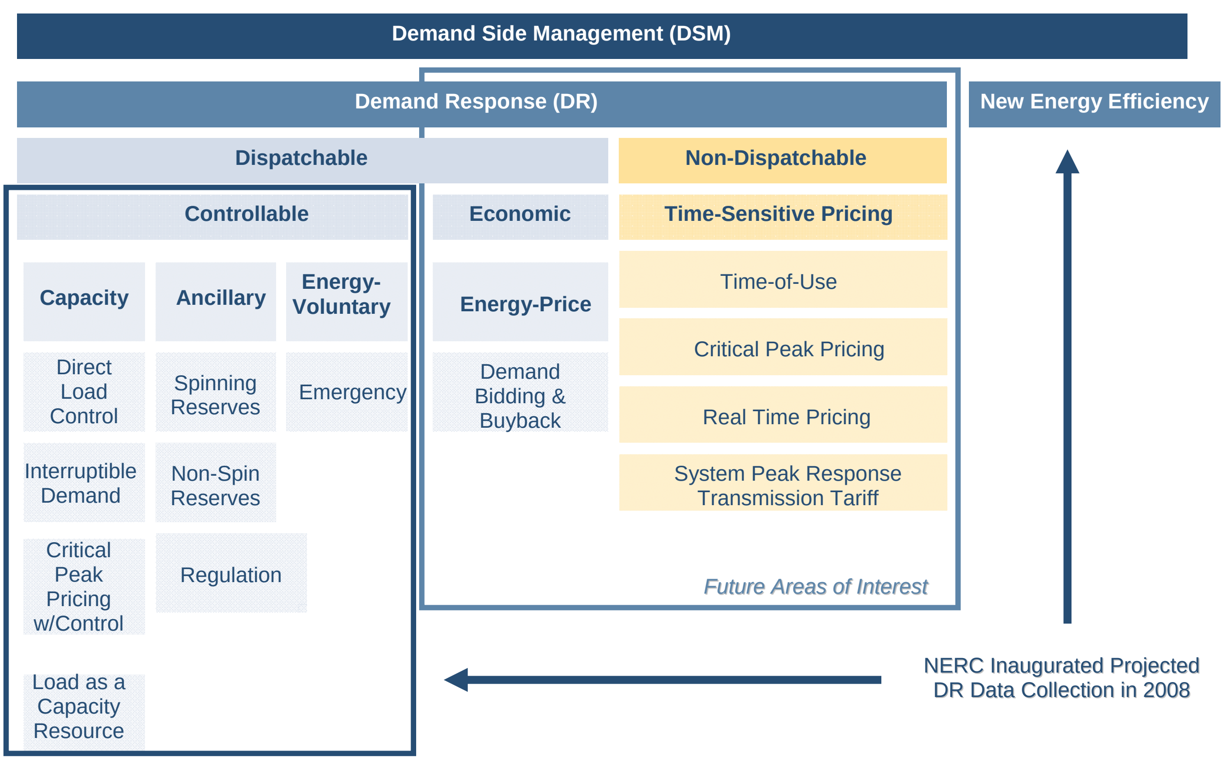
Demand Response Concepts and Categorization

As the industry's use of Demand Side Management (DSM) 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 energy efficiency 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. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use (See Figure Demand 1).

Note the context of these activities and programs is DSM, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. The Demand Response categories defined in *Terms Used in this Report* support Figure Demand 1

Figure Demand 1: Demand-Side Management and NERC's Data Collection



.

Reliability Historic Trends

Introduction
Historical trends of reliability were provided for the first time in NERC's *2008 Long-Term Reliability Assessment*. Understanding these trends can lead to improved BPS reliability. For example, indication of ongoing threats to reliability can stimulate pre-emptive action in future designs and actions thereby maintaining BPS reliability.[244]

There are two basic, functional components of reliability: operating reliability and adequacy.

- Operating reliability is the ability of the interconnected electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.
- Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.[245]

The purpose of this section is to provide an annual update of historic trends in operating reliability and adequacy. This section presents historical performance based on data either collected or obtained by NERC for investigation or analysis. NERC Staff has identified these sets of data as Reliability Indicators,[246] consistent with the objectives of the Reliability Benchmarking Program to identify and track key Reliability Indicators.[247] Reliability Indicators can be used as guides to identify reliability impacts due to the effects of human activities, protection misoperation, transmission loading, and the influence of equipment failures on the reliability performance. The Transmission Loading Relief (TLR) analysis is presented to respond to the following NERC Action from the *2008 Long-Term Reliability Assessment*:

- *Support the RWMG's activities to study and improve upon historical reliability metrics and trends. Specifically, this group should focus on expanding this analysis beyond the Eastern Interconnection. In addition, support root cause analysis of trends in the number of TLRs and other similar mechanisms.*

Trends of relatively diminishing performance identified during the analysis may indicate the need for further investigation of possible reliability concerns. NERC is actively collecting information and analyzing data on a number of leading Reliability Indicators with the objective to identify and eliminate unreliable actions and at-risk conditions.

Reliability Indicators are used by NERC Staff to monitor areas of interest which are not captured within the current Adequate-Level of Reliability (ALR) Metrics. These Reliability Indicators are

[244] Definition of Adequate Level of Reliability can be viewed at http://www.nerc.com/~members/OC_PC/ALR/ as of December 12, 2007.
[245] NERC Glossary of Terms ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf
[246] NERC Reliability Indicators website: http://www.nerc.com/page.php?cid=4|37
[247] NERC *Rules of Procedure: Section 809* http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20090616.pdf

not a product of the Reliability Metrics Working Group which focuses on metrics associated with ALR.

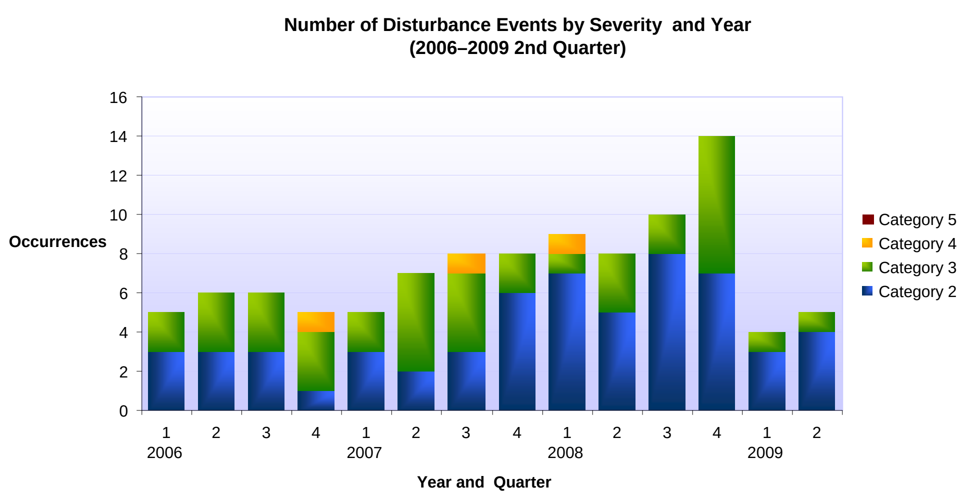
Trends in Operating Reliability

Disturbance Event Trends — NERC's Bulk Power System Event Classification Scale classifies operating reliability system events according to five Operating Reliability Events Categories with Category 5 being the most severe. (See "NERC's Bulk Power System Event Classification Scale" and "Operating Reliability Events Categories" in *Terms Used in this Report* for a detailed definition with category level explanations.[248]) Based on data from NERC's Disturbance Analysis and Event Tracking database, Figure Trends 1 depicts all Category 2 through 5 system events between 2006 and the second quarter of 2009.[249] The events caused by factors other than the performance of the transmission system are not included.

This data indicates there have been no Category 4 and 5 events since the second quarter of 2008 and the number of Category 3 events increased in the fourth quarter of 2008 (seven events), representing the highest number of Category 3 events within a quarter within the period.

Potential gaps may exist between actual performance and expected performance under operating conditions and may indicate a need for guidance to the industry in the form of advisories or changes to the standards development plan. A focus on performance based standards is one possible response. Ultimately, improvements in operating reliability would result in the number of events declining towards zero.

Figure Trends 1



[248] Classification Scale is also available at http://www.nerc.com/page.php?cid=5|252.

[249] See http://www.nerc.com/page.php?cid=5%7C63%7C252 and *Terms Used in this Report* for detailed definitions. Note that disturbance trend information presented in this report was developed using the current eventclassifications for all years presented (2006, 2007, 2008 and 2009) and may differ from previous reports that used earlier versions of the classification scale.

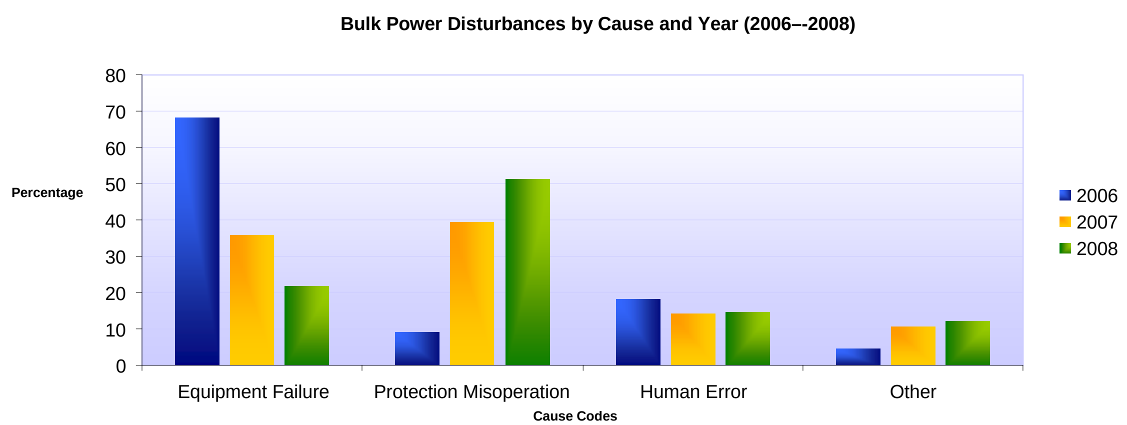
Figure Trends 2 summarizes the contribution between 2006 and the first quarter of 2009 trending period of the three leading causes to the total number of events: equipment failure, misoperation of protection systems and controls, and human error. Definitions of these cause codes are in Table T2.

Table T2: Definition of Cause Codes
Equipment Failure Events caused by the failure of equipment. Use this code only when the equipment failed even though it was operated within design specifications. The failed equipment could be (i) a component of an Element (such as a failed insulator), or (ii) part of an AC Substation (such as a failed circuit breaker), **Protection Misoperation** Events caused by relay and/or control initiated operations when not desired or the failure to operate when desired. This category also includes incorrect relay or control settings that do not coordinate with other protective devices. **Human Error** Events caused by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner will be identified and reported in this category. Also, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported.

Misoperation of system protection and control systems has been the leading cause of BPS disturbances in North America for a number of years, contributing nearly 40 percent of Category 2 and higher disturbances in 2007, more than 50 percent in 2008.

NERC has launched a comprehensive initiative[250] designed to coordinate ongoing efforts to improve the performance of power system protection and control systems, and thereby limit the scope and severity of future system disturbances. The initiative prioritizes efforts, focusing on relay loadability, protection system redundancy, protection system coordination, generator frequency and voltage protective relay coordination, transmission and generation protection system misoperations, and protection system maintenance.

Figure Trends 2



[250] See http://www.nerc.com/news_pr.php?npr=295 for detailed initiative.

Trends in Adequacy

Adequacy is the ability to supply load, or demand for electricity at all times.[251] Measuring the capacity and energy deficiency based on Energy Emergency Alerts (EEAs) in steady-state conditions will indicate decreasing or increasing adequacy providing a correlation between EEA events and reserve margins for future planning recommendations. Analysis has identified transmission constraints, extreme weather, short-term load forecast errors, and unplanned generation outages are the main causes of these emergency events.

As noted in the *2008 Long-Term Reliability Assessment*, the definitions for EEA's are in need of revision, specifically in reference to the use of demand response programs. NERC continued to work with the industry and committees to revise EEA definitions in 2009. EEA2 events calling solely for activation of DSM or interruption of non-firm load per applicable contracts are excluded from this trend.

Review of the historical record revealed more than 75 percent of EEA3 events were issued following declarations of TLRs in response to transmission constraints, as shown in Figure Trends 3. Among them, 68 percent of EEA3 events called between January 1, 2005 and July 15, 2009 were preceded by TLR level 5 declarations, when firm-load interruption was imminent or in progress.

The Transmission Loading Relief (TLR) process is used by reliability coordinators (RC) in Eastern Interconnection (EI) to operate the system within real-time reliability limits, while respecting transmission service reservation priorities. RC's issue TLR directives in which rights for specific transactions are revoked until BPS conditions allow their resumption. TLRs have different levels with Level 6 being the most severe. Trends towards increasing numbers of TLR Level 5 or higher indicate certain parts of the transmission system are at their limit to supply requested transfers within reliability constraints.

Level 5B TLR's have risen significantly from 2002 to 2008, with over 85 occurring in 2008 as compared with only five in 2002.[252] A level 5B TLR is called in the Eastern Interconnection to curtail firm transactions as more power is scheduled to travel over a given transmission pathway than can be accommodated.

As described in the 2008 *LTRA*, since the implementation of the EIS market in 2007, SPP has experienced an increase in the number of TLR events primarily due to SPP publishes congested facilities by issuing TLRs. Thus far, in 2009, SPP has experienced an increase in the number of hours in TLR Levels 3 and 4 and a decrease for time spent in Level 5 TLRs. The main reason for the increase in Levels 3 and 4 was lengthy construction outages associated with important system upgrades. During construction work, TLRs were relied upon extensively to control loading in the areas impacted by the outages. SPP estimates that 40 percent of the TLR hours during the first seven months of 2009 were related to transmission system upgrades.

[251] Definition is available at http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.
[252] TLR 5b trends are available at http://www.nerc.com/page.php?cid=4|37|257|272.

SPP has begun to notice positive effects of these transmission upgrades as evidenced in Figure Trends 4; during the first seven months of 2009, the SPP RC Area experienced 592 Level 5 TLR hours. This is a decrease of 20% compared with the same period during 2008.

Figure Trends 3
EEA 3 Events by Cause
(January 1, 2005 - July 15, 2009)

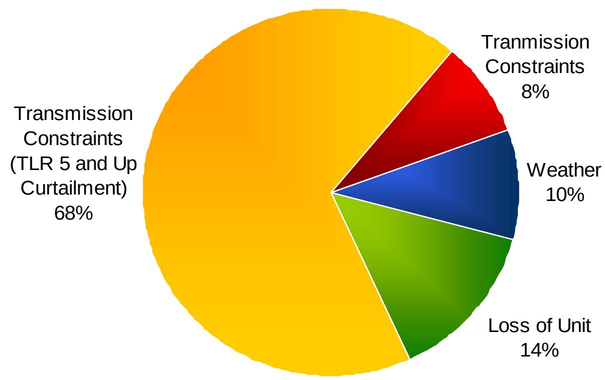
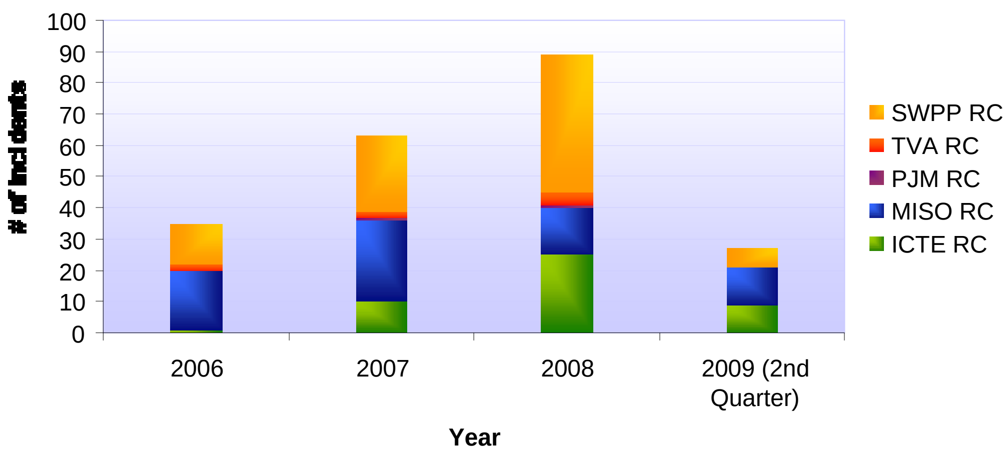


Figure Trends 4
Eastern Interconnection Level 5b Transmission Loading Relief Requests (2006-2009 2nd Quarter)



SPP is working with its members to develop market protocols that will allow SPP to abstain from issuing TLRs for congestion that can be only be resolved by the market. SPP has recently begun implementing this new process on the SPPSPSTies[253] flowgate. This process duplicates other Regional market's procedures in which the loading of internal flowgates is controlled with market re-dispatch without declaring TLRs.

[253] Definition is available ahttp://www.spp.org/publications/2B4_flowgate_01_13_2006.xls

Fuel Supply Analysis: Coal, Natural Gas, and Uranium

Independent analysis performed by Energy Ventures Analysis, Inc.[254]

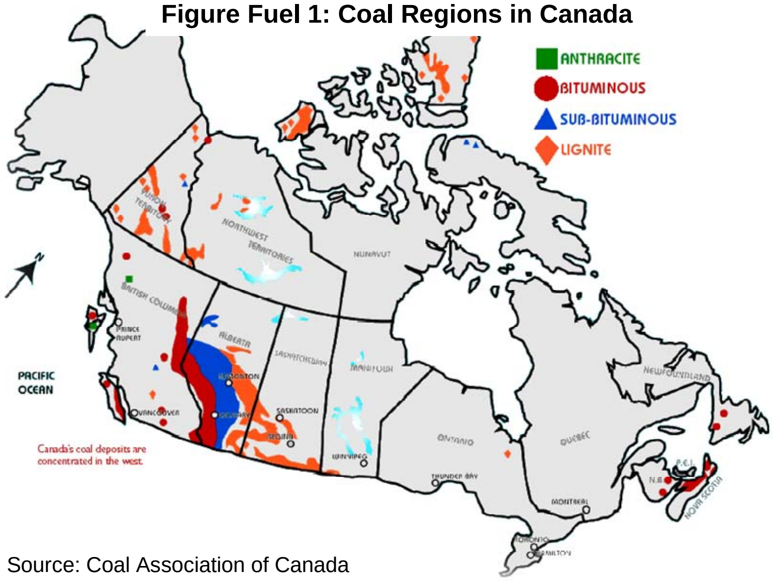
Coal

Outlook for Reliability of Coal Supplies for the Electric Power Industry

Historically, coal has been the fossil fuel with the highest reliability of supply and the most stable price for the electric power industry. Coal supply grew steadily from 1980 to 2000, with few years where production fell, normally tied to an economic recession and a decline in demand. The supply growth led to the expansion of the huge coal fields in the Powder River Basin (PRB) in Wyoming (See Figure Fuel 2),[255] where low-cost coal was shipped long distances in increasingly-efficient unit trains. Canada, Figure Fuel 1, has fewer coal supplies.[256] Coal prices fell from 1980 to 2000 in constant dollars, fueled by growth in labor productivity of mining operations.

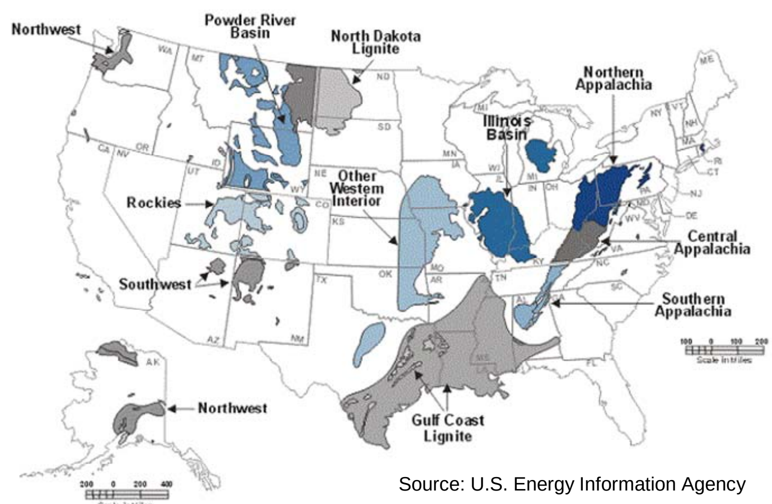
This situation began to change in 2001, when the industry experienced a short-term price increase because demand rose during the winter and customer

Figure Fuel 1: Coal Regions in Canada



Source: Coal Association of Canada

Figure Fuel 2: Coal Regions in the U.S.

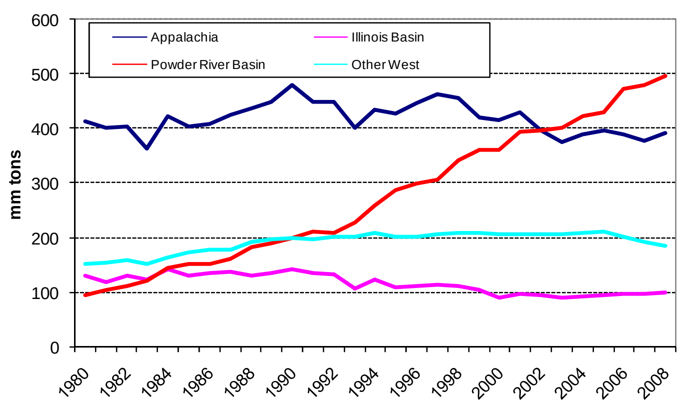


Source: U.S. Energy Information Agency

[254] http://www.evainc.com/
[255] http://www.eia.doe.gov/cneaf/coal/page/trans/figs1.gif
[256] http://www.coal.ca/content/index2.php?option=com_jce&task=popup&img=images/stories/coal_map.gif&title=&w=800&h=612&mode=1&print=0&click=0

inventories were at low levels. While this price increase evaporated in 2002, with lower demand and increased supply, temporary supply shortages recurred in 2004 and 2008, accompanied by even-greater price shocks. The repetition of these short-term disruptions is a clear indication that the United States. coal industry no longer has the excess production capacity to respond to surges in demand. Other sectors of the coal supply chain have sought to minimize excess capacity as well, as customers have reduced coal stockpile levels and transportation companies have eliminated excess capacity. Further, productivity in coal production has declined steadily since its peak in 2000 (Figure Fuel 3), as mining conditions have become more difficult and mining regulations have become more restrictive. As a result, there is reason for the electric power industry to be more concerned in the future about the reliability of coal supply than before.

Figure Fuel 3: U.S. Regional Production 1980 to 2008



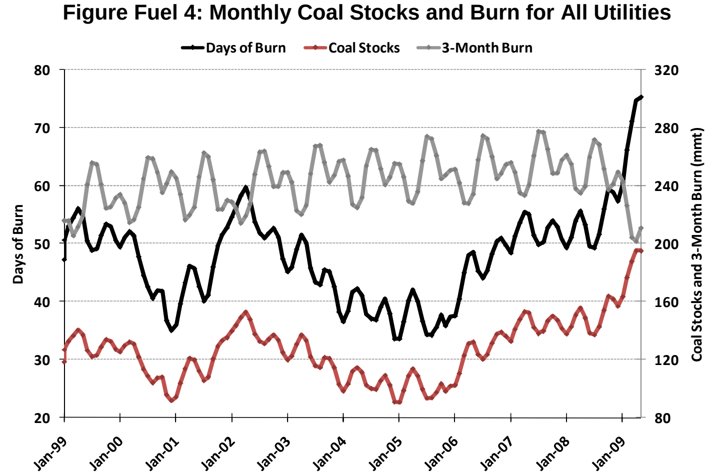
Source: Energy Ventures Analysis, Inc.

The principal areas of increased concern for the reliability of coal supply are:

1. Potential for Supply Shortages in 2010 to 2012 Due to the Recent Recession.

   The recent decline in coal burn due to the recession of 2008 – 2009 has been unprecedented (Figure Fuel 4). Prior to 2009, coal burn in the electric power sector only fell in four separate years (1982, 1986, 2001, and 2006), with the largest drop in coal burn of 2.2 percent in 2001. During the first half of 2009, coal burn has fallen by over 11 percent from 2008. The major reasons for this sharp decline are: 1) lower electricity demand due to the recession; 2) increased generation from non-fossil sources of power (nuclear, hydro, and wind); and, 3) displacement of coal generation by natural gas CCGT plants as the slump in industrial gas demand and increased gas supply has pushed this fuel into the power sector.

Figure Fuel 4: Monthly Coal Stocks and Burn for All Utilities

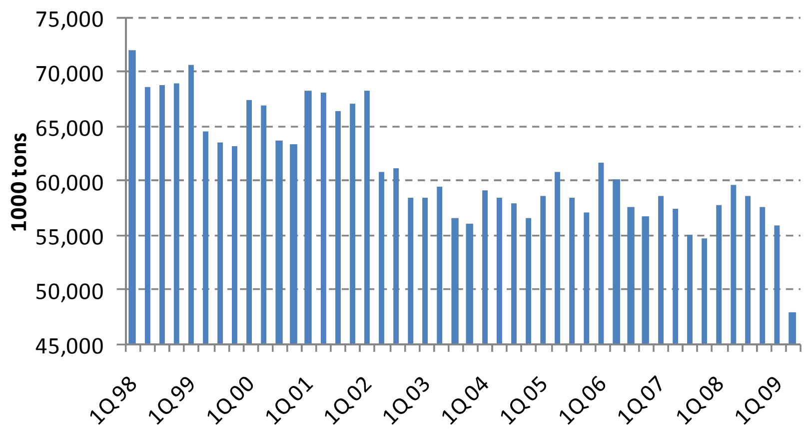


Source: Energy Ventures Analysis, Inc.

   The drop in coal demand has led to sharp increases in customer stockpiles, as power companies continued to take delivery of coal contracted when demand expectations were higher. Power company stockpiles have grown to levels not seen in the industry before.

The power companies have begun to cut back deliveries to match the lower burn and are likely to cut further to bring inventories down during 2010. The reduced purchases by power companies have forced mine closures, especially in Appalachia, where the cost of production is higher than the rest of the industry. The demand for this coal is down by more than 20 percent. Coal production in Central Appalachia (the second-largest producing Region after the PRB) fell to only 48 million tons in the second quarter of 2009, compared to a previous low of 56 million tons (Figure Fuel 5).

Figure Fuel 5: Quarterly Central Appalachian (CAPP) Coal Production



Source: Energy Ventures Analysis, Inc.

There is a significant possibility that coal burn will rebound when the recession ends and economic growth in the United States recovers. Many forecasts predict this will occur in 2010 or 2011. This will bring both increased demand for electricity and increased demand for natural gas in the industrial sector, both of which would stimulate a return of coal burn to previous levels. A rapid recovery of coal burn could lead to a supply shortage in this time frame, as production will be slower to recover, especially in Appalachia, where the barriers to entry have continued to grow. It is much harder to obtain a mining permit than before and the mining is more labor-intensive, which could lead to labor shortages if demand rebounds.

2. Regulatory Restrictions on Surface Mining in Appalachia

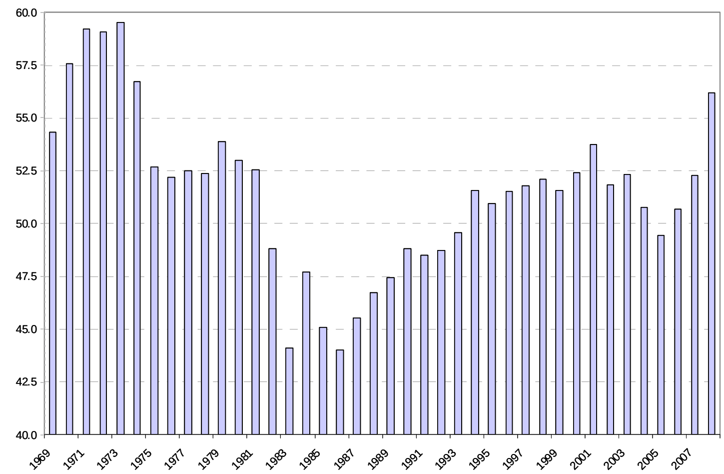
In recent years, there has been a growing controversy surrounding the practice of mountaintop-removal mining. This practice involves mining multiple seams and placing the rock removed in mining into "valley fills", which are terraced in the heads of "hollows" in the hills. The regraded landscape is rolling terrain, rather than the original steep contour of the mountain. This practice was specifically authorized in the Surface Mine Control and Reclamation Act of 1977 as an alternative to restoring the approximate original contour. Opposition to this form of mining has grown, especially in non-mining areas, as the landscape of mountainous areas has been changed. There have been numerous legal challenges to the practice of disposing of rock in valley fills using the Clean Water Act, based on the claim that the valley fills have an adverse impact on water quality in streams in Appalachia. While none of the legal challenges has been upheld, the new Administration supports the restriction or elimination of mountaintop mining and has delayed the issuance of new valley-fill permits.

Today, surface mining comprises over 50 percent of total production in Central Appalachia and is the principle source of supply of steam coal to the electric power industry, primarily in the Southeast (due to location). The potential elimination of new valley-fill permits will severely restrict this source of supply; with the impact growing over time as coal producers exhaust the production from existing permits. Taken to the extreme, limitations on valley-fill permits could restrict deep mining as well, as rock from mine face-ups and waste from coal cleaning plants need to be disposed of in some fashion.

This potential limitation would have the greatest impact on Eastern power companies, including Canadian power companies in Ontario and Nova Scotia, and would force them to use coal supplies from more distant supply regions, such as the PRB and the Illinois Basin, as well as more imported coal. This will create longer supply chains and higher delivered prices. Further, these coals are not always suitable for use in boilers designed for Appalachian coal, due to lower heat content and lower ash fusion temperatures.

Natural Gas

Figure Fuel 6: Annual Average U.S. Dry Gas Production (Billion cubic feet per day)



Source: Energy Ventures Analysis, Inc.

Recently, the United States began to reverse a flat to declining production trend, largely as result of the shift toward unconventional gas production (Figure Fuel 6). Figure 1 shows that 2008 United States dry gas production increased by 5.5 BCFD from 2006.[257] Compared to conventional gas plays, unconventional gas plays can be drilled at a faster pace with little exploration risk and have higher productivity and longer life wells. They are found in shale, tight sands, and coalbed methane reservoirs and are geographically widespread with exceptionally large reserve potential. In its latest biennial assessment, the Potential Gas Committee increased United States. gas resources by nearly 45 percent to 1,836 trillion cubic feet (TCF), largely as result of increases in unconventional gas in the Appalachian basin, the Arkoma and Fort Worth basins of the Mid-Continent, the Uinta basin of the Rocky Mountains, and several Gulf Coast basins. In addition, the Horn River shale of British Columbia, while still in its infancy, is considered a world class field and one of the most important natural gas basins in North America. A shift to unconventional gas production in North America will tend to increase the reliability of ample long-term supply in the future.

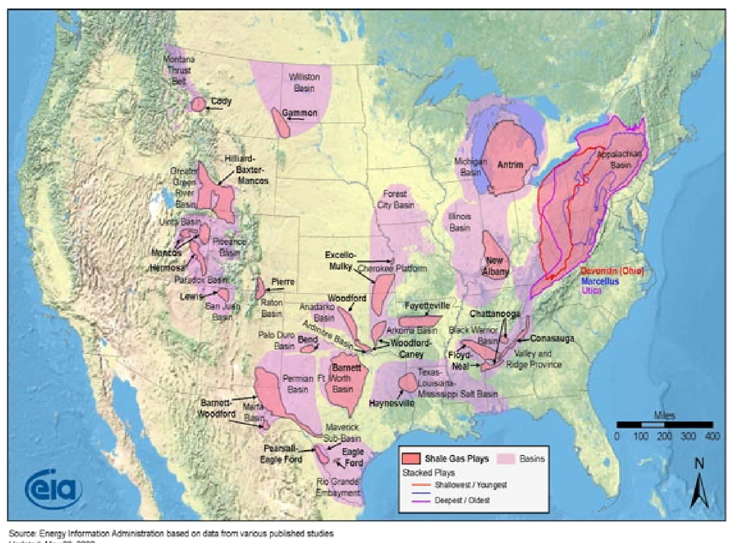
[257] Gas production in 2005 was adversely affected by Hurricanes Katrina and Rita and is not a good base year for comparison.

Successful development of unconventional gas in North American basins is dependent on advanced technology that requires horizontal drilling of well bores, hydraulic fracturing of the rock with large amounts of high-pressure water, and real-time seismic feedback to adjust the stimulation method. Access to this technology is reducing the cost of production for unconventional gas resources. Issues that may adversely affect future production from unconventional resources include access to, and drilling permits for, lands that hold the resources, availability of water, wastewater disposal, and unfavorable state and provincial tax regimes or royalty structures.

Figure Fuel 7: Canadian Shale Gas Basins

Source: Unconventional Gas Resources

Figure Fuel 8: U.S. Shale Gas Basins



Source: U.S. Energy Information Agency

Water issues are specifically a concern for the Marcellus and Utica shales in the state of New York and the Marcellus shale in the Delaware and Susquehanna River Basins that feed into the Chesapeake Bay system. A national debate is underway about the efficacy of existing regulation by state water quality agencies over natural gas drilling. A change to federal jurisdiction has been proposed, which would tend to raise the cost of production, although water-availability issues must be monitored closely as they have the potential to interrupt, or delay, gas development. States such as Pennsylvania, where development is in its infancy, are also debating increases in state severance tax levels, which can also hinder the pace of development. Figure Fuel 8 shows the location of major unconventional shale gas plays in the Lower 48 States and Figure Fuel 7 shows shale plays in Canada.[258] Maps for tight sands and coalbed methane plays also follow this section.

Changes in the gas exploration and production industry have been accompanied by a renaissance in gas transportation and delivery infrastructure, facilitated by FERC market-based rate structures, pipeline capacity release programs, and asset management programs. Deliverability

[258] http://www.ugresources.com/images/unconventionalgas_gasshales.jpg

of new United States gas pipelines increased by 15 BCFD in 2007 and 44 BCFD in 2008, with an increase of 35 billion cubic feet per day (BCFD) likely in 2009. Also maximum effective working gas storage capacity may expand from 3.8 TCF to about 4.3 TCF by 2011, if most projects are completed on-time. Thirdly, liquefied natural gas (LNG) regasification capacity is set to expand to 12 to 21 BCFD by 2012.

These large-scale expansions of the United States gas transportation and delivery infrastructure significantly increases the levels of insurance and flexibility needed to alleviate short-term supply dislocations from potential events such as pipeline outages, production outages, or hurricanes. For example, the new Perryville Hub in Louisiana, which is several times larger than the Henry Hub, specifically offers inland protection against hurricanes. Excess capacity at LNG regasification facilities will also be able to fill large domestic supply gaps, although sufficient waterborne LNG cargoes may take three to seven days to arrive as they are diverted away from foreign demand centers. Generally, upward local price adjustments will serve as the signal to attract additional domestic or international supply towards the disruption.

To meet electric power cycling and peaking requirements, pipeline transportation and storage contracts can be restructured, to some degree, for greater intra-day and intra-seasonal deliverability. Increased flexibility can be secured at higher tariffs, while the pipeline expands compression capability. However there are limits to such expandability especially as natural gas further penetrates the electric grid. High deliverability storage caverns also tend to be limited, are not necessarily located near demand centers, and are subject to geological constraints, not just engineering constraints. Some Regions remain devoid of access to nearby storage, particularly in the western United States.[259]

Natural gas-fired generation produced 21 percent of the electricity in the Lower 48 States during 2008. By 2018, this share is projected to climb to 26 percent, and then escalate to 30 percent by 2025.[260] Market share of natural gas in the generation mix will climb for several reasons including: 1) gas being the economic choice for a large number of new capacity decisions, 2) gas providing substitute capacity for fast-growing renewable generation, such as wind, which can experience variability and sudden declines in availability and 3) gas replacing the energy produced by higher carbon-content fuels, with United States. coal capacity expected to peak in 2013.[261] All of these items point to gas demand increasing from 18 to 22 BCFD by 2018 just in the electric sector, and escalating another 4 BCFD by 2025. Natural gas demand also could surge higher, and quite suddenly, if gas is called upon to meet any shortfall, or delay, in electric generation planned from Renewable Portfolio Standards,[262] new nuclear plants, energy efficiency programs, and DSM programs, or if the economy recovers more robustly than anticipated.

A reversal of the decline in Canadian natural gas production is also important for North American supply reliability, as 90 percent of United States net imports were from Canada in 2008 and Canadian natural gas demand is projected to increase fairly rapidly. The unlocking of

[259] http://www.nerc.com/files/LTRA2008.pdf
[260] Energy Ventures Analysis, Inc., *FUELCAST: Long Term Outlook*, August 2009.
[261] Energy Ventures Analysis, Inc., *FUELCAST: Long Term Outlook*, August 2009
[262] This includes the ability of most states to modify their RPS targets on an annual basis due to either cost or reliability concerns.

stranded conventional gas supplies from the Arctic and Alaskan North Slope is dependent on a mainline Alaskan gas pipeline being built. While this gas will be required to meet needs beyond 2018, any outstanding issues must be resolved in today's timeframe, in order for FERC to process the pipeline application during 2012–2013 in order for companies to begin construction by 2014. While the likelihood of an Alaskan gas pipeline has increased considerably over the past year, many potential obstacles remain unresolved within the gas industry, FERC, and other agencies such as Canada's National Energy Board. FERC has stated that it has manpower to process only one of two competing mainline Alaskan pipeline projects. Also, "because there have been no filings for Canadian permits by any Alaska natural gas sponsor, the severity of this potential problem cannot be determined."[263] One illustration of delay in pipeline development is visible in the unresolved royalty claim of the Del Cho First Nation in Canada that is preventing significant advancement of the smaller MacKenzie Delta Pipeline.

While prices are not normally a concern for reliability, their level and volatility drive the pace of overall gas resource development, with sufficient return on capital (e.g., market price) required to stimulate new production. The current low price environment poses some concern for gas, as drilling rig counts are about one-half of the prior year, as the industry attempts to restore equilibrium from an oversupplied condition in 2009. Because the industry is focusing on unconventional gas wells and United States drilling is at a seven-year low, the decline in deliverability from conventional gas wells will accelerate, and this trend poses a risk, if unconventional production is unable to replace it in the long-term. Total United States gas production is projected by the EIA to decline in both 2009 and 2010.[264] In 2008, Canada replaced about 90 percent of its annual production despite depressed drilling rates. The precise annual rates of growth of gas production from the newer formations, which are still in their infancy, are uncertain given the large amount of new drilling that is required to extract the gas.

New leading edge and best practices for unconventional gas plays (Figures Fuel 9 and 10) have been reported with breakeven production costs, in some cases, below $4 per mmBtu (assumes 2009 dollars and NYMEX Henry Hub),[265] although this level of market price is not sufficiently high enough to replace all of the gas that is consumed in the United States each year. Constant dollar (2009) values approaching $7 per mmBtu may be required to develop the unconventional gas resources required to meet 2018 gas demand.

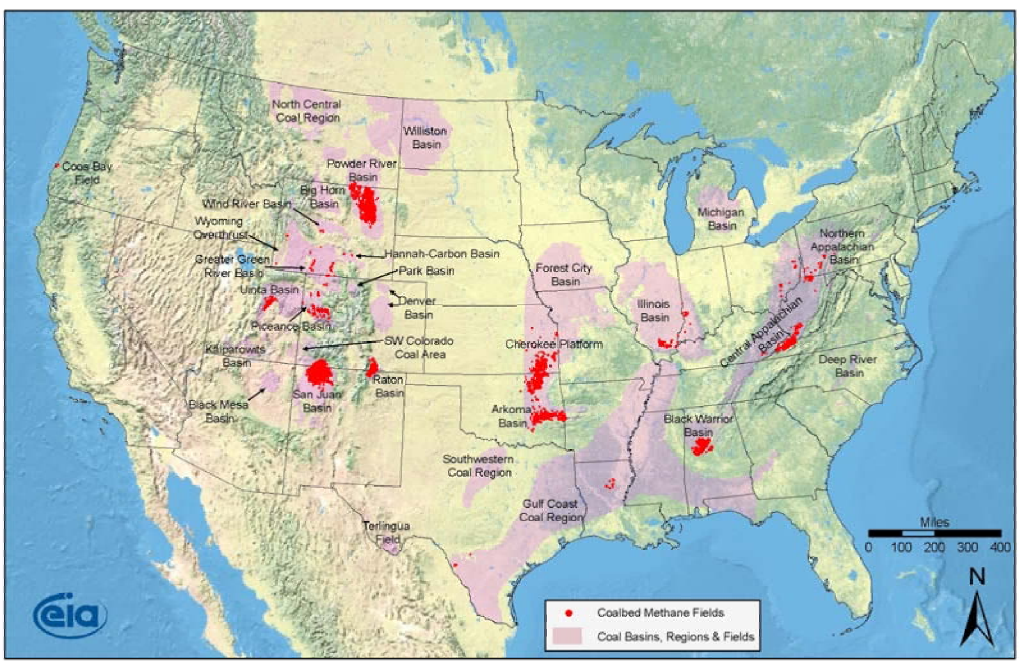
[263] http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf
[264] http://www.eia.doe.gov/emeu/steo/pub/jul09.pdf 2009. EIA projects a decline of 0.6 percent in 2009 and 2.9 percent in 2010.
[265] Breakeven NYMEX price assumes delivery at Henry Hub.

Figure Fuel 9: U.S. Tight Gas Plays

Source: Energy Information Administration based on data from various published studies
Updated: April 8, 2009

Source: U.S. Energy Information Agency

Figure Fuel 10: U.S. Coalbed Methane Fields



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Source: U.S. Energy Information Agency

Uranium: Nuclear fuel supply cycle

Nuclear fuel supply cycle

The primary nuclear fuel cycle consists of five basic steps:

1.. mining of natural uranium ore rich in ^{238}U isotope (99.3 percent) and ^{235}U isotope[266] (0.7 percent);
2. transforming the ore into uranium concentrate, triuranium octoxide (U_3O_8);
3. converting concentrate into uranium hexafluoride (UF_6);
4. enriching to higher percentages of ^{235}U;
5. fabricating fuel into rods that are suitable for commercial nuclear reactors.

North America has limited capacity in most of these stages of the nuclear fuel cycle due to 25 years of underinvestment and the highly sensitive nature of the technologies, the large capital costs, the large-scale of the required industrial operations, and safety concerns. North American dependence on imported supplies of enriched uranium may leave it vulnerable to supply disruptions, particularly as world needs for enriched uranium increase.

Primary mining of uranium is provided by two general methods either by direct extraction of ore from underground or by in-situ leach recovery methods. However for many years, the United States, Canada, and most other Western countries have relied heavily on secondary sources of supply.[267] Secondary supplies are obtained from a number of sources, including the Megatons for Megawatts Agreement where Russia down blends highly-enriched weapon quality uranium (HEU) into low-enriched uranium (LEU) and exports it to the United States. Enrichment Corp (USEC) through 2013, reprocessing of spent United States civilian reactor fuel, release of inventories from utilities and governments, and potential conversion of United States. ex-military supplies into mixed uranium plutonium oxide fuel (MOX).

Russia's role

Heavy dependence on Russian supplies of enriched uranium is likely to rise further despite organized attempts to create centralized enrichment services that would be controlled by joint world organizations. In 2011, Russia will begin commercial exports of LEU directly to United States utilities of 17 tons in 2011, increasing to 41 tons in 2013, and then rising further after the HEU/LEU Agreement expires, to possibly 485 tons in 2014 and 514 tons by 2020.[268] Commercial imports were made possible by the United States redefining enriched uranium imports as a service, from a good, and by United States federal trade courts dropping anti-dumping measures that prevented commercial imports. Russia estimates that such deals will enable it to garner a larger share of the United States market from 23 to about 30 percent by about 2013.[269] Russia also exports enriched uranium to Canada, Europe, and Asia. In July 2009, President Obama and President Medvedev of Russia signed a new agreement to further reduce the ceiling on strategic nuclear warheads from the current level of 2,200 warheads to about 1,500

---

[266] ^{235}U is the fissionable material.

[267] "Western" countries include former Soviet Republic countries such as East Germany, Kazakhstan, Uzbekistan, and the Czech Republic

[268] http://www.bellona.org/articles/articles_2007/Uranium_USimports

[269] http://www.bellona.org/articles/articles_2009/us_russia_uranium

warheads within seven years, which, if ratified by the U.S. Senate, would be expected to provide additional source material for higher Russian exports to international markets.[270]

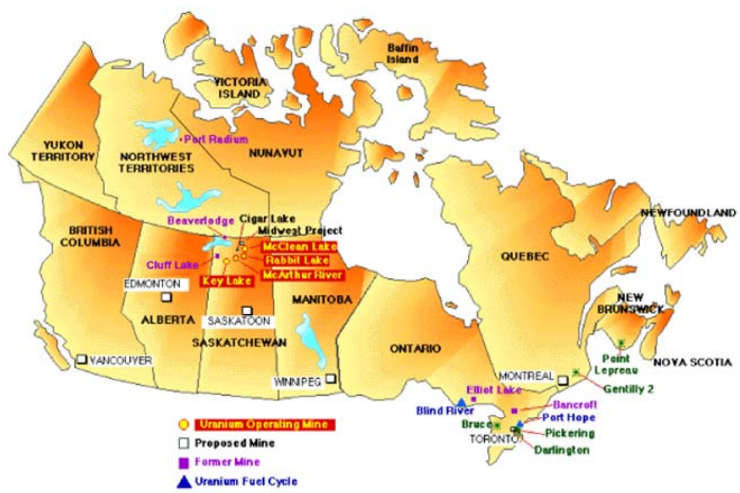
Uranium supply

After a long period of only two mines operating in the United States, total U.S. mine production increased by about 114 percent in 2006 from 2003, and then fell by 17 percent, to 3.9 million pounds of concentrated uranium (U_3O_8) in 2008. There were 17 operating mines and also one operating ore mill in 2008. Other United States mills were on standby status, or were processing alternate feedstock ores such as vanadium. Wyoming and New Mexico provided the majority of the ore, with four other states (Colorado, Utah, Arizona, and Nebraska) producing the remainder. United States. exploration and development for uranium also increased rapidly in the recent past, although it was nearly flat in 2008 with total drilling down by 1 percent to 5.1 million feet and the number of holes drilled up 8 to 9,355.

The Neuclear Regulatory Commission (NRC) is currently reviewing applications for five new in-situ recovery mine facilities (four in Wyoming), with processing of each application expected to take about two years. Eighteen additional applications for in-situ leach recovery mines are anticipated by the NRC through 2012.

By comparison, Canada is the world's largest producer of natural uranium, followed by Australia and Kazakhstan, although Canadian production has been slowly declining over the past six years falling to 9,476 tons of uranium metal in 2007.[271] Saskatchewan, as shown in Figure Fuel 11, represents a substantial amount of Canada's uranium production.[272]

Figure Fuel 11: Canadian Uranium Mines, Production, and Power Plants



Source: Wealth Minerals, Ltd.

Limited enrichment capacity

There is limited capacity in United States nuclear fuel cycle processes given almost 25 years of underinvestment, with enrichment perhaps the most constrained. Canada has no enrichment facilities, and instead exports natural uranium and re-imports enriched uranium. In fact, there are only four commercial entities involved in enrichment activities in Western countries.[273] Both primary, and many secondary,

[270] http://www.nytimes.com/2009/07/07/world/europe/07prexy.html?_r=1&pagewanted=print
[271] http://www.cigionline.org/sites/default/files/NEF_5.pdf
[272] http://www.canadianminingnews.com/canmap.gif
[273] AREVA (France), URENCO (governments of Britain, the Netherlands and Germany), Tekhsnabexport or Tenex for short (Russia), and U.S. Enrichment Corp. (USEC).

supplies of uranium are critically dependent on the enrichment process, where a higher percentage of ^{235}U atoms are extracted.

Uranium supply and the use of enrichment processes are considered partial substitute factors. Demand can be shifted between the two at an optimal rate that is dependent on the cost of uranium and the cost of enrichment, assuming there are ample separative work units (SWU)[274] to run enrichment processes and sufficient mining capacity to supply the primary product. In effect, a higher percentage of ^{235}U atoms can be obtained if more SWU are employed, offsetting the amount of UF_6 that is consumed to manufacture the same amount of enriched uranium. However this is not the case for the United States, Canada, and most Western countries. The two factors are not perfectly substitutable because there is limited SWU capacity and limited mining capacity. For combined capacities of uranium supply and SWU supply including secondary sources, MIT estimated, even using the most efficient processes,[275] a Western country shortfall of 27 million SWU in 2015 when analysis was based on planned and potential capacities, with the shortfall increasing to 45 million SWU when based only on planned capacities.[276]

While the industry has functioned thus far during periods of over- and under-supply largely by market price adjustments to both uranium and SWU, the large number of new international nuclear power plants expected to come online by 2018 may create a supply shortage of enriched uranium. Presently there are 49 reactors under construction in 13 countries, most notably China, South Korea, Japan, and Russia, with nameplate capacity of 44 MWe. About 70 more reactors are planned to come online in the next eight years, also with some 25 emerging countries actively considering nuclear power. Further complicating this dilemma, United States. enrichment plants and United States reactors were designed around processes that create higher amounts of waste, therefore requiring higher amounts of uranium. New fast reactor technologies that use more SWU and lower amounts of uranium operate in Russia, France, and Japan, with others under construction in India and China.

The USEC currently has one operating enrichment plant at Paducah, Kentucky with capacity of 8 million SWU per year. USEC has another 3.5 million of new SWU capacity planned by 2015 and 3.5 million more of potential capacity. National Enrichment Facility (NEF) has 3 million of new capacity planned for 2013 at its Eunice, New Mexico plant, with potential to expand to 5.9 million SWU per year by 2015 if approved by the NRC. Areva proposes to build the Eagle Rock Enrichment Facility near the DOE Idaho National Laboratory in Idaho Falls to start in early 2014, ramping up to full capacity of 6.6 million SWU per year by 2019. And finally, Global Laser Enrichment (GLE) processes are under development and testing using Separation of Isotopes by Laser Excitation (SILEX) laser technology. GEL submitted a full application to NRC, although the commercial decision to proceed is not expected until late 2009. The application would take about 30 months to process with an initial online date of 2013 and capacity in the 3.5 to 6.0 SWU per year range. New United States MOX facilities are split evenly between total planned and potential capacity of 2 million by 2015. All of these plans

[274] SWU take into account the amount of waste in the assay tails during the enrichment process. For instance, an assay tail of 0.4 percent implies higher waste compared to a tail of 0.2 percent.

[275] Those which produce assay tails of only 0.1 percent.

[276] Neff, Thomas L, *Uranium and enrichment: supply, demand & price outlook*, MIT Press, 2007.

should be monitored closely given the expected surge in worldwide demand for nuclear fuel and limited enrichment capacity in the United States.

Data Checking Methods Applied

NERC's Reliability Assessment Data Validation and Error Checking Program ensures 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 and 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 Data Checking 1). 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 Data Checking 1: 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
Currentness *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	• 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)	5,000	5,000
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	1,345
6b7	Scheduled Outage - Maintenance	4,000	2,398
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 and 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 Long-Term 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.

Regional Data Checking Methods

In 2009, the DCWG conducted a survey of data checking methods applied at the Regional level. The goal for NERC was to better understand the processes and frameworks Regions work with to handle reliability assessment data submittals. For the Regions, this activity fostered sharing of best-practices, identified process gaps, and shared lessons learned.

The following questions provided a guide for Regional DCWG representatives to describe the data-checking procedures performed in support of *Long-Term Reliability Assessment* data.

1. *Describe the method in which data is gathered and ultimately submitted to NERC.*
    a. *Include a description of an intranet or Internet-based "Portal" system, if applicable.*
        i. *Identify the types of Registered Entities (members) required to submit data.*
        ii. *Identify any data checks that are built-in to the "Portal" system.*
        iii. *Describe any security measures in place. (e.g., password protected, limited access, etc.)*
    b. *For Regions where the majority of data is generated by an ISO/RTO, describe how the data is accumulated at the Regional level.*
2. *Describe how your Region validates data and then ensures that data is properly reported.*
3. *Describe any special procedures used to identify data errors. (e.g., cross-checking against historical data, visualizing/graphing data points)*
4. *Describe the method in which data errors are resolved.*
5. *Give a brief overview on the coordination efforts between your Region and members for providing high-quality data. (e.g., committee description and activities)*

ERCOT

ERCOT obtains data pertaining to its interconnected generation from a variety of sources. For existing units that participate in the market, the owners register each unit and supply the latest effective capacity obtained from testing. For units that are part of a private use network (most of their generation is self serve), the owners will provide ERCOT a statement of the maximum output available at peak for all the units at their site. For planned units, the developers supply us with all the necessary data (expected online data, nameplate capacity, etc.). Planned units are studied but not considered as firm capacity commitment until a contract (called an interconnection agreement) has been signed between the developer and the transmission provider and all required permits have been secured.

Data validation is performed by cross checking values across several other databases, such as historical values and the settlement system that supplies interval output data per unit. Any inconsistencies or errors identified are resolved as soon as possible through phone calls or e-mails to the appropriate party.

For registration and planning purposes, uniform spreadsheets have been developed to capture the myriad of data necessary for the accomplishment of multiple purposes.

FRCC

Regional data is obtained by the RRO from those entities that have been classified according to NERC Reliability Standards as a LSE, Planning Authority (PA), Resource Planner (RP), and/or Transmission Planner (TP). Data collected from these entities is done in accordance with the requirements outlined in NERC MOD (Modeling) Standards MOD-16-001, MOD-17-001, MOD-18-001, and MOD-19-001. Non-Regional data is similarly collected for member utilities not within Regional boundaries but reside with the state of Florida; such data is used to complete other reports mandated for submittal to the Florida Public Service Commission.

The FRCC employs a secured Internet-based portal system to collect data from registered entities within the Region. FRCC ensures limited and secure access to the online collection system by restricting access to selected individuals at member utilities. Such authorized users are provided with a login name and unique software-generated password for system access, while WebEx training is conducted by FRCC staff with new users on the proper use and operation of the data portal. An annual review is conducted by FRCC staff on the list of authorized users to ensure that only users with required access are granted continued permission to access their online data.

The FRCC employs three levels of data checking to help ensure the highest degree of data integrity.

- The first level of data checking is contained in FRCC's online data portal, commonly referred to as the Load and Resource Database (LRDB). This database system contains base-level data checking capabilities, which ensure users input data is consistent with the selected data type fields, and input values are within prescribed ranges based upon commonly accepted values. Data satisfying these initial criteria are accepted for input into the LRDB before more rigorous levels of data checking are initiated.
- The second level of data checking involves the use of macro-enabled Excel workbooks that extract users data from across related tables to ensure data consistency is maintained for the like variables (e.g., demand, energy, etc.) that are located in separate data fields across different forms. Any data inconsistencies detected are resolved with the respective users via e-mail and/or phone. This process is repeated until all such identified discrepancies have been eliminated.
  A numerical variance report is also generated by FRCC staff to compare the current year's data to the prior year's reported data. Such data is examined for data outliers, and combined with various graphing techniques as a sanity check to ensure current trends are not significantly different from past historical trends, unless it has been determined that there are identifiable driving factors that would support observed variations (e.g., large decrease in load forecast based upon lessened demand as a result of depressed economic conditions). Once this has been completed, data checking is progressed to the final stage for review.
- The final step of data validation is performed after all members data has been complied into a high-level summary plan for both the Region and State, referred to as the Regional Load and Resource Plan (Plan). This composite plan provides an overview for both the

Region and state, and is reviewed by the FRCC Resource Working Group (RWG), the FRCC Transmission Working Group (TWG), the FRCC Load Forecasting Working Group (LFWG), and the FRCC LRDB Users group (who are those responsible for inputting data into the LRDB). Following the identification and adjustment to any components of the plan, it is passed before the FRCC Planning Committee for final review. Data contained within the plan is used for assessments, reports, and other filings as may be required by NERC, EIA, and/or state governmental entities.

To further increase the accuracy of collected data, the FRCC has assembled the LRDB Improvement Task Force (LITF) composed of LRDB users and members from the various working groups, which have been involved in the review of the collected data. This task force is presently collaborating with FRCC's IT and DCWG staff in the development of XML-enabled workbooks that will perform the first two levels of data checking mentioned earlier, and allow for the bulk upload of users data. The designed XML-based arrangement will enable real-time detection of data errors by users, and be expanded to contain additional data integrity checks as identified and required for future data collections. This new setup will employ digital certificates to ensure data security, and has been planned for operation at the beginning of the 2010 data collection period. Beta testing is scheduled to begin September 2009.

MRO

Once MRO staff members acquire the applicable NERC forms (i.e., ERO-2009Long-Term Reliability Assessment.xls), a data request email is developed and submitted to the applicable MRO registered entities. This data request contains the NERC instructions set (i.e., *NERC 2009 Long-Term Reliability Assessment Instructions*) as well as Region-specific instructions as to how to complete the NERC form. The Region-specific instructions typically address how the data submitter is to handle the NERC form at their own respective subregional level. Specific examples include instructions on how to handle transactions data, wind resource data, and proposed/conceptual capacity data.

Once all the data is received from the data submitters, MRO staff members compile the data using internal VBA-developed macros applicable to handling the populated Long-Term Reliability Assessment spreadsheets. Once the TO and GO data is compiled, MRO staff populate the resulting spreadsheets with data obtained from other external resources. The final spreadsheet set includes separate workbooks for MRO-US, MRO-Canada, and MRO-Total.

MRO instructions to data submitters require them to omit wind resources. Wind data fields are populated by MRO staff from data collected by a separately handled request. This request is better suited for capturing wind resources in the MRO Region, specifically IPP-related wind resources. The "conceptual" capacity data is developed by collecting the "Active" projects listed in the various interconnection queues of the tariff providers within the Region. This includes the Midwest ISO, MAPPCOR, Manitoba, Saskatchewan, and the Nebraska companies. The list is filtered to eliminate any unrealistic or redundant projects, to the best of MRO staff ability. MRO staff members then develop an applicable confidence factor to attempt to capture what might actually be realized, based on historical queue data.

Once all the data has been compiled, additional data checking is done against previous year's submissions, known developments, and reasonable assumptions. Inquiries are made to data submitters as needed.

Automated data validation is limited to what is built into the applicable NERC forms (i.e., ERO-2009Long-Term Reliability Assessment.xls). MRO does not alter or remove these data validation checks unless we perceive them to be counterproductive to the data collection process. To date, MRO has never added additional data validation checks to the NERC forms.

If a data error is suspected, MRO staff will contact the appropriate entity to discuss it. A data error is typically resolved by working with the entity through a phone call or e-mail.

Once the data is compiled into a Regional total and the narrative is written, the MRO Transmission Assessment Subcommittee reviews the transmission portions of the report and the MRO Resource Assessment Subcommittee reviews the resource portions of the report. Finally, the MRO Reliability Assessment Committee reviews the entire report and approves it before it is sent to NERC.

NPCC

The Northeast Power Coordinating Council conducts its resource assessments and all planning analyses through the five NPCC Reliability Coordinator Balancing Authorities, defined by the following footprints:

- the Maritimes 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 (ISO New England Inc.);
- New York (New York ISO);
- Ontario (Independent Electricity System Operator); and
- Québec (Hydro-Québec TransÉnergie).

The data necessary for any study effort is solicited from these five areas. For the seasonal and long term reliability assessments, two working groups provide representatives from the New Brunswick System Operator, the ISO-NE, the New York ISO, the Independent Electricity System Operator, and Hydro-Québec TransÉnergie. Each RC representative is responsible for the submission of the needed study data as well as its accuracy and integrity. For the RAS efforts, the NPCC Working Group Operations Planning Working Group (CO-12) is charged with the submission of the summer and winter seasonal data; for the long term analyses, the NPCC Working Group CP-08, "Working Group on Review of Resource and Transmission Adequacy," assumes the responsibility.

RFC

In the Reliability*First* Region, data is generated by the PJM and MISO RTOs and the OVEC BA in response to an instruction letter sent by Reliability*First* via e-mail and followed up as necessary with phone calls to the RTOs. The Regional values from the spreadsheets are simply added together and submitted to NERC via spreadsheet. Reliability*First* reviews and adjusts the RTO import/export values at the Regional level to eliminate the intra-Regional component of RTO import/export from jointly owned units and OVEC owner entitlements.

All data is validated through cross checking of data between different schedules, comparison to prior year's data, and aggregation of zonal demand and generator data to RTO subtotals. Any data discrepancies or questions are resolved through e-mail, revised spreadsheets, and phone calls.

SERC

SERC Reliability Corporation has invested considerable resources into the development and maintenance of a secure Portal information system. This SERC Portal serves as the interface between SERC staff and registered entities for the collection and dissemination of data and information including, but not limited to, that required for completion of NERC reliability assessments.

Within the SERC Portal, there are three areas directly related to the NERC reliability assessments: demand and energy, capacity, and transmission. Each area contains one or more data input forms that closely imitate those provided in the NERC ERO data request workbook. The Portal forms are assigned to all entities registered in the SERC Region based on their registration function(s), and data submittals are monitored by SERC staff. It should be noted that data coordination may eliminate the requirement for a registered entity to respond if another party agrees to report on their behalf. A list of such arrangements is updated by registered entities and maintained by SERC staff.

A user ID and password is required to access the secure SERC Portal. Individual data forms are further restricted by roles, or permissions; e.g., in order to access a reliability assessments transmission data input form, a user must have a user ID and password, and also have the appropriate permissions assigned to their account to view and/or edit the data on the transmission form.

The majority of the data validation is performed outside of the SERC Portal at this point. Currently, there are validation routines programmed on certain forms to ensure required data fields are supplied (e.g., capacity transfer forms, transmission additions forms, etc.). Additional data-checking criteria are in development for the 2010 data reporting cycle, including checks for demand and energy data streams and capacity validation. The SERC Portal is a dynamic system, and further improvements will be considered for future development.

After registered entities have completed their data submittals via the SERC Portal, the data is aggregated offline to a subregional level. Data is reviewed at the subregional level by SERC staff and the SERC Reliability Review Subcommittee (RRS). The RRS is comprised of subregional representatives with extensive industry experience. The subregional data review includes historical comparisons and data charting. When data errors or anomalies are discovered, the submittals for individual entities comprising that subregion are analyzed to determine the origin of the problem; a resolution is then initiated with the reporting party. If, in fact an error is discovered, the data is resubmitted via the SERC Portal and the data is aggregated again for the subregion; if the data is correct as reported, the issue is documented.

Communication between the SERC staff and registered entities takes place via the SERC Data Collection Task Force (DCTF). The DCTF meets on an annual basis to train reporting entities on Regional expectations and to discuss changes in the reporting requirements. Conference calls are also conducted, and e-mails exchanged, on an ongoing, as-needed basis.

SPP

SPP data is currently gathered from the reporting entities via spreadsheet. The spreadsheet request is sent out to the reporting entities, which is then aggregated into one master spreadsheet providing the totals for the entire SPP Region. This is the first year SPP had a formal peer review process internally. New validation points were identified and checked internally. SPP currently validates the different schedules to ensure consistency. Other validation points include cross-checking prior year data to the current year. Demand and capacity data are verified with SPP reporting entities. Currently, SPP does not employ any visual graphics to identifying suspect data; however, this function will be added in the future.

SPP kicks-off the data collection process with a WebEx/conference call with all of its reporting entities. Once this is complete, all coordination is done through e-mail, spreadsheets, and phone calls. SPP may add new coordination efforts this year, but plans have not been finalized.

WECC

WECC data are gathered via data request spreadsheets that are filled in by all of the balancing authorities within the Western Interconnection. The data contained in the request spreadsheets are then accumulated into a master spreadsheet that aggregates the raw data into summaries by Region and subregion and exports the aggregated data to the data reporting spreadsheets provided by NERC.

Data validation is accomplished largely through a series of checks built into the data request spreadsheet. For example, year-to-year load growth rates are compared and off-trend values are highlighted. The reporting entity is asked to provide a written explanation regarding any off-trend load growth. Peak resources data are compared to existing generation and generation additions information and differences are presented to the reporting entity in both tabulated and graphic form. To facilitate identification of discrepancies, the comparisons are summarized by resource type.

As noted above, the data request spreadsheets incorporate tabular and graphic summaries to identify conflicting or off-trend data. Also, WECC staff compares updated data against the prior year’s data and staff is expected to question unexpected year-to-year changes in reported data. Staff follows up with balancing authorities to resolve all issues. The reporting entities are contacted regarding questionable data and are expected to either revise the data or provide a written explanation as to why to questionable data are correct.

WECC's Loads and Resources Subcommittee oversees the reliability assessment process and reviews the *Long-Term Reliability Assessment* narrative information. The subcommittee operates under the purview of WECC's Planning Coordination Subcommittee (PCC). The PCC representatives of all BAs are responsible for the data submittals to the WECC Staff. As necessary, PCC representatives of entities that are not BAs may be solicited by BAs for data that is not otherwise routinely available (e.g., scheduled maintenance for non-utility generation).

External Data Validation

NERC's Reliability Assessment Data Validation and Error Checking Program includes demand and supply projections from external sources. This section explains the external data validation aspect of the program and provides information on the external sources with their projection assumptions.

Data validation is a process for ensuring correct and useful data. One element of this process is internal data checking and validation — NERC achieves this for assessment reports through a rigorous semi-automated process outlined in the *Data Checking Methods Applied* section of this report. The second element of this process involves comparisons to external sources. Consistent with NERC's role to provide independent and comprehensive assessments of bulk power reliability, this report includes comparisons to external sources for demand and supply forecasts. These external sources include Canadian and United States government agencies, non-governmental organizations, industry working groups, and consultants with expertise in electricity demand or supply forecasting. For a robust comparison base, NERC includes external forecasts developed by complex macroeconomic and power-flow models. NERC staff has reviewed the sources included in this report to ensure that their work is unbiased, reflects current industry practices, and represents acknowledged and credible information.

As an enhancement to future assessments, NERC expects to broaden the list of sources used for comparisons. However, meaningful forecasts in this arena are limited to a narrow group of agencies, organizations, groups, and companies — many of which are already represented here. This is particularly true for electricity demand forecasting. Several organizations producing such forecasts are for-profit companies with proprietary models, restricting the use of their data.

The Data Validation and Error Checking Program also includes limited external validation of transmission projects. NERC uses a news aggregation service to review public news articles, press releases, corporate filings, government filings, and online industry news sources to track the progress of transmission projects. The results of this review are then compared against the transmission project data and information data obtained from Region members, and any resulting inconsistencies are shared with Region members for further examination.

Regions report capacity and demand related to reliability not as a function of an economic model or based on extreme "system stress" case. This generally involves 50/50 demand forecasts and various levels of capacity planning certainty. The forecast values provided below may represent extreme cases based on 90/10 demand forecasts or modeling values, which rely on economic assumptions. Readers are advised to review the assumptions provided for each source to explain any significant differences. Further the inclusion or exclusion of capacity transactions (imports or exports) across NERC Region-geographic boundaries may result in differences between NERC values and external sources. (NERC's capacity values reflect Firm capacity transactions. See *Terms Used in this Report* for details.) This is particularly true for FRCC.

External sources referenced in this report are listed below with the assumptions for their forecasts. A brief source summary is provided for readers unfamiliar with the entity. The sources are grouped by their presentation topic in this report then alphabetically by a commonly known abbreviation or shortened title. (These abbreviations or shortened titles appear in the tables used in this report.)

The "NERC Demand Range" in Table Data Validation 1 represents uncertainty bandwidths calculated by the Load Forecasting Working Group (LFWG) for the Regions, the United States, and Canada[277] For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes (e.g., 50/50 forecasts provided by each Region to NERC), but also of the distribution of probabilities around the projection. Therefore, the LFWG develops upper and lower 10 percent confidence bands around the NERC Regional peak demand and energy forecasts. This means that there is a long-run 80 percent probability that future demand and energy will occur within these bands. Conversely, there is a 10 percent chance that future outcomes could be less than the lower band, and a 10 percent chance that future outcomes could be higher than the upper band.

The LFWG does not calculate uncertainty bandwidths for subregions. Therefore, subregion demand ranges provided in Table Data Validation 1 include Net Internal Demand as a low range value and Total Internal Demand as a high range value. One value is presented instead of a demand range if Net Internal Demand equals Total Internal Demand—this is the case for some subregions, which report Demand Response as capacity resource or do not have Demand Response resources. The range for Total-NERC represents LFWG uncertainty bandwidths plus Net Internal Demand and Total Internal Demand values for the WECC CA-MX Mex subregion.

The "NERC Capacity Range" in Table Data Validation 2 includes Deliverable Capacity Resources as a low range value and Adjusted Potential Capacity Resources as a high-range value.

[277] http://www.nerc.com/filez/lfwg.html

Table Data Validation 1: Forecast Total Internal Demand, by NERC Region and Subregion								
	2009		2018					
source:	**NERC Demand Range** (GW)	ERAG (GW)	**NERC Demand Range** (GW)	EIA (GW)	EVA Case 1 (GW)	EVA Case 2 (GW)	ERAG [2019] (GW)	Venytx (GW)
United States								
ERCOT	62 - 65	NA	70 - 82	68	65	70	NA	78
FRCC	44 - 48	47	48 - 59	53	53	57	59	54
MRO	41 - 46	47	41 - 58	NA	44	48	57	49
NPCC	58 - 65	62	54 - 79	59	64	68	73	69
New England	28	30	31	26	29	30	35	31
New York	33	32	35	32	36	38	38	38
RFC	167 - 189	189	163 - 240	NA	194	208	226	202
RFC-MISO	61 - 62	NA	65 - 67	NA	64	69	NA	68
RFC-PJM	110 - 116	NA	128 - 135	NA	129	139	NA	134
SERC	196 - 210	219	222 - 253	182	217	232	252	233
Central	41 - 43	42	45 - 49	NA	45	48	48	49
Delta	27 - 28	36	31 - 32	NA	28	31	41	35
Gateway	19	21	21	NA	21	22	23	21
Southeastern	48 - 50	54	59 - 61	NA	56	60	65	57
VACAR	62 - 64	67	73 - 75	NA	67	71	76	71
SPP	43 - 46	45	47 - 53	47	47	50	52	56
WECC	135 - 147	NA	144 - 183	144	166	178	NA	162
AZ-NM-SNV	30	NA	36 - 37	NA	38	40	NA	37
CA-MX US	58 - 61	NA	64 - 69	58	71	75	NA	66
NWPP	39 - 40	NA	46 - 47	NA	45	48	NA	43
RMPA	11	NA	13	NA	13	14	NA	16
Total-U.S.	**745 - 814**	NA	**788 - 1,007**	**828**	**850**	**910**	NA	**903**
Canada								
MRO	6 - 7	9	7 - 8	NA	NA	NA	7	6
NPCC	46 - 51	61	44 - 55	NA	NA	NA	60	56
Maritimes	3	4	3 - 4	NA	NA	NA	4	4
Ontario	24	30	22	NA	NA	NA	31	28
Quebec	21	27	23	NA	NA	NA	25	24
WECC	18	NA	21 - 23	NA	NA	NA	NA	22
Total-Canada	**70 - 76**	NA	**71 - 86**	NA	NA	NA	NA	**84**
Mexico								
WECC CA-MX	2	NA	3	NA	NA	NA	NA	3
Total-NERC	**817 - 892**	NA	**863 - 1,095**	NA	NA	NA	NA	**990**

Specific NERC demand projection values for Regions and subregions are located in the *Estimated Demand, Resources, and Reserve Margins* section of this report.

Demand Data Validation (Table Data Validation 1)

EIA Assumptions

Energy Information Administration
1000 Independence Ave., SW
Washington, DC 20585
www.eia.doe.gov

The mission of the Energy Information Administration (EIA) is to provide policy-neutral data, forecasts, and analyses to promote sound policy making, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. Created by the Congress in 1977, EIA is the statistical agency of the U.S. Department of Energy and as such is the Nation's premier source of unbiased energy data, analysis and forecasting. By law, EIA's products are prepared independently of Administration policy considerations. EIA neither formulates nor advocates any policy conclusions.[278]

Forecast title: *Annual Energy Outlook 2009* and results produced for NERC August 2009.
Forecast type: macroeconomic model
Data vintage: November 2008

EIA develops projections in the Annual Energy Outlook 2009 generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting of the EIA. The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the period through 2030, approximately 25 years into the future. In order to represent Regional differences in energy markets, the component modules of NEMS function at the Regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; the NERC Regions and subregions for electricity; and the Petroleum Administration for Defense Districts for refineries.

The Electricity Market Module of NEMS represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generating plants, including capital costs and macroeconomic variables for costs of capital and domestic investment; environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules — capacity planning, fuel dispatching, and finance and pricing. All specifically-identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several

[278] http://tonto.eia.doe.gov/abouteia/mission_overview.cfm

states, primarily in the Northeast, have recently enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in AEO2009. Although currently there is no Federal legislation in place that restricts greenhouse gas (GHG) emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the AEO2009 reference case through a 3-percentage-point increase in the cost of capital when investments in new coal-fired power plants without carbon control and sequestration (CCS) and new coal-to-liquids (CTL) plants are evaluated.

EIA collects and reports data based on 13 Electricity Market Module Regions, which roughly reflect pre-1997 NERC Regions.[279] Accordingly, a direct comparison of EIA Market Module Regions and current NERC Regions or subregions is not possible for all subregions and these areas are identified as "NA" (not available) in the validations tables in this report.

EVA Assumptions

Energy Ventures Analysis, Inc.
1901 N. Moore St., Suite 1200
Arlington, VA 22209-1706
www.evainc.com

EVA specializes in energy and environmental market analysis and forecasting for natural gas, coal, electricity, oil, NO_x, SO_2, and CO_2 . EVA does project analysis, including project performance and financial evaluations for existing and proposed power plants, coal mines and coal companies, natural gas storage projects, and other energy projects.[280]

Forecast title: none—special forecast provided to NERC
Forecast type: macroeconomic model
Data vintage: Spring 2009

EVA Electricity Forecast

Case 1: EVA's base forecast is based on the following assumptions:

- The recession will end in the last half of 2009, and Real Gross Domestic Product (GDP) will grow at a 3–5 percent rate in the recovery period of 2011–13, and 2.5 percent afterwards.
- About half of the loss in industrial electricity demand is expected to recover when the economy improves with the remainder permanent.
- Very little coal fired-capacity will be added beyond the 21,000 MW either under construction or in the advanced development stage.
- 15,000 MW of new nuclear plants are projected in the forecast period, but most of it is in the 2016–2018 period.

[279] http://www.eia.doe.gov/oiaf/aeo/supplement/supmap.pdf
[280] http://www.evainc.com/about.htm

- Combined-cycle generation (CC) capacity will bridge the gap for baseload capacity before the nuclear plants can be developed with 84,000 MW of new CCs in the 2009–18 forecast period.
- Renewable plants, primarily built to meet Renewable Portfolio Standards, will add 27,000 MW of new capacity during the 2009–18 forecast period.
- Environmental and economic/age issues will result in the retirement of 24,000 MW of coal-fired capacity and 38,000 MW of oil/gas steam units in the 2009–19 forecast period.
- Reserve margins for the United States are projected to remain in the upper 20's during the forecast period. Note EVA's capacity and Reserve Margins are higher than reported by NERC because EVA includes all merchant plants and any capacity available to be sold onto the grid. EVA capacity numbers do not include self-generators. The Regions where the Reserve Margins are near the target levels include NPCC-New England, RFC-PJM, SERC-Gateway, SERC-VACAR, SPP, and WECC-CA.
- CO_2 legislation is expected to pass and will begin in 2012 with a cost of CO_2 allowancing at \$15/ton CO_2 in 2009 dollars, escalating at 5 percent real thereafter.
  - Higher electricity prices
  - Lower electricity demand particularly in the industrial sector
  - Higher CC and lower coal plant capacity factors due to CO_2 costs

Case 2: The no CO_2 legislation case has the following impacts:

- Higher electricity demand with lower electricity prices.
- Industrial demand recovers about two-thirds of its losses in 2008 and 2009.
- Higher growth rate increases need for new capacity in some Regions.
- With higher demand, the national Reserve Margin in 2018 declines from 28 percent in the base case to 21 percent in No CO_2 Legislation case.
- Coal plants run at higher capacity factors during 2012–2018 period because of lower dispatch costs, while CC plants run at lower capacity factors.

ERAG-MMWG Assumptions

The Eastern Interconnection Reliability Assessment Group
Multiregional Modeling Working Group
www.erag.info/MMWG.aspx

The Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) includes direct representation from the Regions in the Eastern Interconnection as well as a working group power flow and dynamics coordinator(s), a liaison representative of the NERC staff, and corresponding representatives from the ERCOT and WECC Regions. The ERAG Management Committee (MC) appoints the Chairman and Vice Chairman for two-year terms. The Group is charged with the responsibility for developing and *maintaining a library of power flow and dynamics base cases for the benefit of ERAG members.*[281]

Forecast title: none — special forecast provided to NERC
Forecast type: power flow model
Data vintage: 2008

The MMWG models power-flow in the Eastern Interconnection. NERC Region member utilities provide power-flow data to the MMWG that creates a base case for 1, 5, and 10 year forecasts, including summer and winter peaks. The MMWG Coordinator and most Regional member utilities employ Siemens Power Technologies Inc. (PTI) Power System Simulator (PSS™E) software for power-flow modeling. All interchanges must net to zero for all models. Each Region is to perform an N-1 screening of its BPS for the purposes of identifying modeling errors before submitting their data to the model coordinator.

This report uses data from the 2019 Summer case for peak load. Summer Peak Load is defined as the summer peak demand expected to be served, reflecting load reductions for peak shaving. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before July 15. Summer interchange schedules reflect transactions expected to be in place on July 15. Planned summer maintenance of generation and transmission should be reflected in the operating year case. Loads are not reduced for application of controllable demand-side management, curtailment of interruptible loads, or for emergency procedures such as voltage reductions and the anticipated effects of public appeals. The effects of uncontrolled demand-side management (peak shaving) are reflected in the modeled load of summer and winter peak load cases. Wind generation should be dispatched at seasonally expected dispatch values, which typically have been 20 percent or less of the nameplate capability of the aggregate wind plant installations. The power flow model will be based on a load forecast, which assumes a statistical probability of one occurrence in two years (50/50).

Though the MMWG does not make demand and supply forecasts, they do deploy forecasts in their detailed models to test system conditions used to support planning and operations. These models often are the basis for studies referred to by Regional entities in their reliability assessments.

Ventyx Assumptions

Ventyx
3301 Windy Ridge Parkway, Suite 200
Atlanta, GA 30339
www.ventyx.com

Ventyx is a business solutions provider to global energy, utility, communications, and other asset-intensive organizations. Ventyx offers expertise in asset management, energy trading and

[281] http://www.erag.info/Documents/MMWG/MMWG%20Procedure%20Manual.pdf

risk management, mobile workforce management, energy operations, customer care, energy analytics.[282]

Forecast title: Advisor's North American Reference Case
Forecast type: North American fundamental market model
Data vintage: August 2009

Ventyx produces a 25-year Reference Case forecast for electricity, fuel, emissions, and renewables, which is updated twice per year. Primary data sources for the forecast include Ventyx Velocity Suite and Advisory Services. The summer peak demand by NERC subregion represents Ventyx's forecast of summer peak demands less Demand Response capacity. The demand forecast in the table is a non-coincident forecast accumulating 325 market zones into NERC subregions. The capacity forecast by NERC subregion represents Ventyx's view of existing generation, unit additions, refurbishments, and retirements. The table projects summer dependable capacity for thermal resources assuming all units are available. Renewable resource nameplate capacity (e.g., wind and solar) is reduced to values that can be relied on during summer peak conditions. Hydro units represent capacity and energy output under normal water conditions. Projected capacity additions, retirements, refurbishments, and retrofits are driven by economic and policy assumptions embedded in the Reference Case forecast.

[282] http://www.ventyx.com/pdf/ventyx-corporate-overview.pdf

Table Data Validation 2: Forecast Capacity by NERC Region and Subregion							
	2018						
source:	**NERC Capacity Range** (GW)	EIA (GW)	EVA Case 1 (GW)	EVA Case 2 (GW)	IEA (GW)	Canada NEB (GW)	Ventyx (GW)
United States							
ERCOT	80 - 85	87	85	85	NA	NA	88
FRCC	63	61	66	66	NA	NA	67
MRO	49 - 54	NA	57	57	NA	NA	56
NPCC	79	77	79	77	NA	NA	82
New England	34 - 37	38	36	34	NA	NA	37
New York	44 - 45	40	44	44	NA	NA	45
RFC	220 - 230	NA	244	242	NA	NA	237
RFC-MISO	71 - 74	NA	83	82	NA	NA	78
RFC-PJM	147 - 155	NA	160	160	NA	NA	158
SERC	262 - 277	221	290	288	NA	NA	270
Central	54 - 56	NA	56	55	NA	NA	59
Delta	36 - 37	NA	52	52	NA	NA	43
Gateway	25 - 26	NA	24	23	NA	NA	25
Southeastern	68 - 77	NA	74	74	NA	NA	65
VACAR	79 - 81	NA	84	83	NA	NA	79
SPP	53 - 63	57	60	58	NA	NA	64
WECC	208 - 211	204	217	213	NA	NA	195
AZ-NM-SNV	43 - 45	NA	48	46	NA	NA	44
CA-MX US	89	75	85	84	NA	NA	68
NWPP	61 - 62	NA	66	66	NA	NA	64
RMPA	15 - 16	NA	18	18	NA	NA	19
Total-U.S.	**1,014 - 1,062**	**1,038**	**1,098**	**1,085**	**1,080**	NA	**1,060**
Canada							
MRO	10 - 11	NA	NA	NA	NA	11	9
NPCC	72	NA	NA	NA	NA	95	85
Maritimes	7	NA	NA	NA	NA	9	7
Ontario	23 - 27	NA	NA	NA	NA	37	33
Quebec	43	NA	NA	NA	NA	48	44
WECC	25 - 29	NA	NA	NA	NA	33	32
Total-Canada	**108 - 112**	NA	NA	NA	**141**	**139**	**126**
Mexico							
WECC CA-MX	3 - 4	NA	NA	NA	NA	NA	5
Total-NERC	**1,125 - 1,178**	NA	NA	NA	NA	NA	**1,190**

Specific NERC capacity projection values for Regions and subregions are located in the *Estimated Demand, Resources, and Reserve Margins* section of this report.

Capacity Data Validation (Table Data Validation 2)

EIA Assumptions
See EIA Assumptions above.

EVA Assumptions
See EVA Assumptions above.

IEA Assumptions[283]

International Energy Agency
9 rue de la Fédération
75015 Paris, France
www.iea.org

The International Energy Agency (IEA) is an intergovernmental organization, which acts as energy policy advisor to 28 member countries. Founded during the oil crisis of 1973–74, the IEA's initial role was to co-ordinate measures in times of oil supply emergencies. As energy markets have changed, so has the IEA. Its mandate has broadened to incorporate the "Three E's" of balanced energy policy making: energy security, economic development and environmental protection.[284]

Forecast title: *World Energy Outlook 2008*
Forecast type: macroeconomic model
Data vintage: 2008

The IEA provides medium-to long-term energy projections using a World Energy Model (WEM). The WEM — a large-scale mathematical construct designed to replicate how energy markets function — is the principal tool used to generate detailed sector-by-sector and Region-by Region projections for both the Reference Scenario and the range of alternative policy scenarios. The model is made up of six main modules: final energy demand; power generation; refinery and other transformation; fossil-fuel supply; CO_2 emissions; and investment. The parameters of the equations of the demand-side modules are estimated econometrically, usually using data for the period 1971–2006. Shorter periods are sometimes used where data are unavailable or significant structural breaks have occurred. To take into account expected changes in structure, policy or technology, adjustments to these parameters are sometimes made over the Outlook period, using econometric and other modeling techniques. Simulations are carried out on an annual basis. The WEM makes use of a wide range of software, including specific database management tools, econometric software, and simulation programs.

[283] World Energy Outlook 2008. Summary: http://www.worldenergyoutlook.org/docs/weo2008/WEO2008_es_english.pdf
Assumptions: http://www.worldenergyoutlook.org/docs/annex_c.pdf
[284] http://www.iea.org/about/index.asp

The IEA value presented in the *Capacity Data Validation* section of this report is an estimate of 2015 and 2020 forecast values. The U.S. nameplate capacity of 1,080 GW for 2018 was calculated as a midpoint between 1,051 GW in 2015 and 1,099 in 2020, assuming even annual increases. The WEM provides projected capacity for North America but IEA does not provide sufficient detail to determine what portion represents Canada or Mexico. Therefore, an IEA capacity value for Canada was not included in this report.

Canada NEB Assumptions

National Energy Board
444 Seventh Avenue SW
Calgary, Alberta
T2P 0X8
www.neb-one.gc.ca

The National Energy Board (NEB) of Canada is an independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas, and electric utility industries. The purpose of the NEB is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development, and trade. These principles guide NEB staff to carry out and interpret the organization's regulatory responsibilities. The NEB is accountable to Parliament through the Minister of Natural Resources Canada.[285]

Forecast title: *2009 Reference Case Scenario: Canadian energy demand and supply to 2020*
Forecast type: macroeconomic model
Data vintage: 2008

The *2009 Reference Case Scenario* is an update and extension of the Reference Case contained in the NEB's 2007 report entitled *Canada's Energy Future: Reference Case and Scenarios to 2030.*[286] The 2009 Reference Case Scenario is based on current best estimates of energy price projections, an economic outlook, and government programs existing at this time. Energy demand and supply projections are provided to the year 2020.

Economic projections are a key driver for the Reference Case Scenario projections. Macroeconomic variables including economic growth, gross output, inflation, and exchange rates are used to develop the energy demand and supply outlooks. In the 2009 Reference Case Scenario, Canadian average real GDP growth is 2.1 percent per year over the outlook period. Long-term economic growth is dependent on population, labor force, and productivity assumptions. This rate of growth is slower than in the previous Reference Case Scenario outlook, reflecting more conservative assumptions for productivity growth rates (1.1 percent versus 1.6 percent). The current economic recession is reflected in this analysis. In 2009, economic growth

[285] http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/whwrndrgvrnnc-eng.html
[286] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.pdf

is estimated to be -2.6 percent. Growth is assumed to rebound to + 2.6 percent in 2010. As in many past business cycles, the recession is assumed to be followed by rapid, recovery stage growth. It then returns to trend growth expectations in 2013 consistent with the demographic and productivity assumptions in this analysis.

Ventyx Assumptions

See Ventyx Assumptions above.

Capacity Margin to Reserve Margin Changes

Background[287]

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* 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 and World Report on February 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."

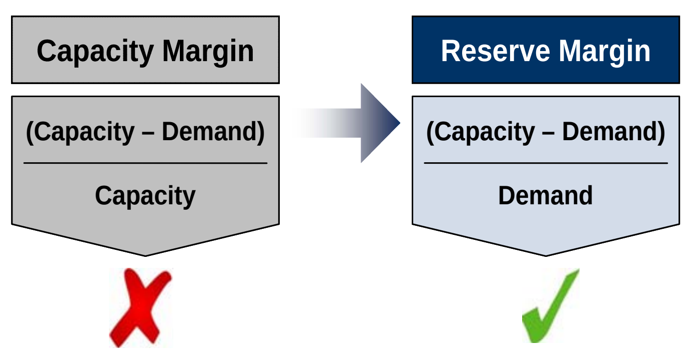
Since the audience of NERC's assessments consists of a wide range of readers (including state and local regulatory bodies), industry terms should be consistent. NERC's goal is to convey reliability assessments in a way that reduces confusion. Since NERC's focus is to maintain BPS reliability in order 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.

This report uses Reserve Margin.

Figure: Reserve Margin to be Used for Future NERC Reliability Assessments



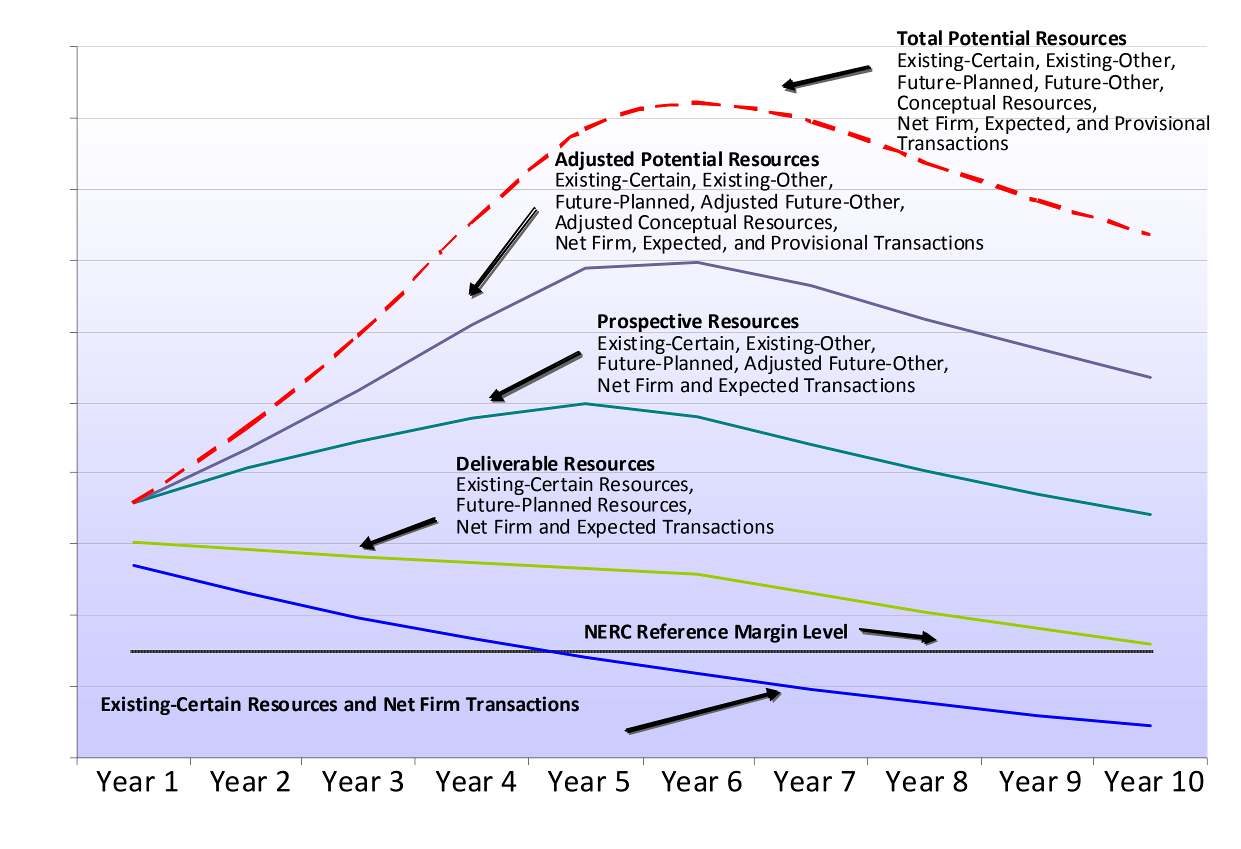
[287] http://www.nerc.com/docs/pc/Updated_PC_Agenda_3-4Dec2008.doc

Estimated Demand, Resources, and Reserve Margins

Reserve Margins, developed for this analysis, are categorized based on the certainty that future resources expected to be available to deliver power within the assessment timeframe are actually constructed and deployed. To improve consistency and increase granularity and transparency, the PC approved new categories[288] for capacity resources, imports and exports (see *Terms Used in this Report* for details). The resource designations of "Existing, Certain," "Existing, Uncertain," "Planned," and "Proposed" have been replaced with:

1. Existing:
   a. Existing, Certain
   b. Existing, Other
   c. Existing, but Inoperable
2. Future:
   d. Future, Planned
   e. Future, Other
3. Conceptual

Figure Margins 1: Example Margins Chart including Definitions



[288] See the section entitled "*Terms Used in this Report*" for definitions that are more detailed.

Table Margins 2a: Estimated 2009 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	63,491	62,376	72,204	72,204	72,204	72,204	72,204	15.8%	15.8%	15.8%	15.8%	15.8%	12.5%
FRCC	45,734	42,531	49,239	51,870	51,870	51,870	53,210	15.8%	22.0%	22.0%	22.0%	25.1%	15.0%
MRO	44,206	41,306	49,648	50,308	50,316	51,098	52,925	20.2%	21.8%	21.8%	23.7%	28.1%	15.0%
NPCC	61,327	61,108	73,678	76,671	76,889	77,579	77,647	20.6%	25.5%	25.8%	27.0%	27.1%	15.0%
New England	27,875	27,875	33,475	33,703	33,921	33,921	33,989	20.1%	20.9%	21.7%	21.7%	21.9%	15.0%
New York	33,452	33,233	40,203	42,968	42,968	43,658	43,658	21.0%	29.3%	29.3%	31.4%	31.4%	16.5%
RFC	178,100	169,900	215,700	215,800	217,600	217,904	219,200	27.0%	27.0%	28.1%	28.3%	29.0%	15.0%
RFC-MISO	62,419	60,719	70,714	70,714	72,308	72,308	72,308	16.5%	16.5%	19.1%	19.1%	19.1%	15.4%
RFC-PJM	116,153	109,653	144,837	144,939	145,113	145,422	146,740	32.1%	32.2%	32.3%	32.6%	33.8%	15.0%
SERC	202,738	196,871	242,787	244,008	256,129	256,129	256,433	23.3%	23.9%	30.1%	30.1%	30.3%	15.0%
Central	42,733	40,874	50,660	50,828	51,196	51,196	51,500	23.9%	24.4%	25.3%	25.3%	26.0%	15.0%
Delta	27,865	27,178	38,433	38,466	38,602	38,602	38,602	41.4%	41.5%	42.0%	42.0%	42.0%	15.0%
Gateway	19,065	18,947	20,306	20,306	21,117	21,117	21,117	7.2%	7.2%	11.5%	11.5%	11.5%	12.7%
Southeastern	49,504	47,789	58,745	58,745	67,788	67,788	67,788	22.9%	22.9%	41.8%	41.8%	41.8%	15.0%
VACAR	63,571	62,083	74,643	75,663	77,426	77,426	77,426	20.2%	21.9%	24.7%	24.7%	24.7%	15.0%
SPP	44,463	43,696	49,706	50,127	56,619	59,557	115,398	13.8%	14.7%	29.6%	36.3%	164.1%	13.6%
WECC	140,692	136,441	172,375	174,978	174,978	174,980	174,985	26.3%	28.2%	28.2%	28.2%	28.2%	17.9%
AZ-NM-SNV	30,452	29,843	35,156	35,076	35,076	35,076	35,077	17.8%	17.5%	17.5%	17.5%	17.5%	17.8%
CA-MX US	61,237	58,421	71,447	71,334	71,334	71,334	71,334	22.3%	22.1%	22.1%	22.1%	22.1%	22.3%
NWPP	39,754	39,155	56,001	57,340	57,340	57,342	57,346	43.0%	46.4%	46.4%	46.4%	46.5%	16.3%
RMPA	11,224	10,939	12,815	13,517	13,517	13,517	13,517	17.1%	23.6%	23.6%	23.6%	23.6%	17.1%
Total-U.S.	780,751	754,229	925,336	935,965	956,605	961,322	1,022,001	22.7%	24.1%	26.8%	27.5%	35.5%	15.0%
Canada													
MRO	6,369	6,082	7,372	7,372	7,372	7,385	7,414	21.2%	21.2%	21.2%	21.4%	21.9%	10.0%
NPCC	48,471	48,026	65,078	66,855	67,456	67,456	67,456	35.5%	39.2%	40.5%	40.5%	40.5%	15.0%
Maritimes	3,499	3,054	5,987	5,987	5,987	5,987	5,987	96.0%	96.0%	96.0%	96.0%	96.0%	20.0%
Ontario	24,351	24,351	28,011	29,788	30,410	30,410	30,410	15.0%	22.3%	24.9%	24.9%	24.9%	17.5%
Quebec	20,621	20,621	31,080	31,080	31,059	31,059	31,059	50.7%	50.7%	50.6%	50.6%	50.6%	9.7%
WECC	18,071	18,071	22,099	22,277	22,277	22,277	22,370	22.3%	23.3%	23.3%	23.3%	23.8%	12.5%
Total-Canada	72,911	72,179	94,549	96,504	97,105	97,118	97,240	31.0%	33.7%	34.5%	34.6%	34.7%	10.0%
Mexico													
WECC CA-MX Mex	2,115	2,115	2,446	2,446	2,446	2,446	2,446	15.7%	15.7%	15.7%	15.7%	15.7%	15.6%
Total-NERC	855,777	828,523	1,022,331	1,034,915	1,056,156	1,060,886	1,121,687	23.4%	24.9%	27.5%	28.0%	35.4%	15.0%

Table Margins 2b: Estimated 2009/10 Winter 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	43,463	42,348	73,916	74,797	74,797	74,797	74,797	74.5%	76.6%	76.6%	76.6%	76.6%	12.5%
FRCC	44,446	40,846	52,751	57,216	57,216	57,216	58,556	29.1%	40.1%	40.1%	40.1%	43.4%	15.0%
MRO	36,904	34,985	48,104	48,417	49,165	49,948	51,774	37.5%	38.4%	40.5%	42.8%	48.0%	15.0%
NPCC	47,098	47,098	76,849	77,577	78,092	78,092	78,561	63.2%	64.7%	65.8%	65.8%	66.8%	15.0%
New England	22,100	22,100	36,210	36,545	37,060	37,060	37,529	63.8%	65.4%	67.7%	67.7%	69.8%	15.0%
New York	24,998	24,998	40,639	41,032	41,032	41,032	41,032	62.6%	64.1%	64.1%	64.1%	64.1%	16.5%
RFC	145,800	140,900	218,000	218,100	219,800	220,104	221,400	54.7%	54.8%	56.0%	56.2%	57.1%	15.0%
RFC-MISO	49,051	47,426	70,714	70,714	72,308	72,308	72,308	49.1%	49.1%	52.5%	52.5%	52.5%	15.4%
RFC-PJM	96,644	93,395	144,837	144,939	145,113	145,422	146,740	55.1%	55.2%	55.4%	55.7%	57.1%	15.0%
SERC	181,045	175,541	248,673	251,192	263,272	263,272	263,701	41.7%	43.1%	50.0%	50.0%	50.2%	15.0%
Central	42,240	40,636	52,618	52,785	53,204	53,204	53,207	29.5%	29.9%	30.9%	30.9%	30.9%	15.0%
Delta	23,023	22,501	40,674	40,707	40,862	40,862	40,862	80.8%	80.9%	81.6%	81.6%	81.6%	15.0%
Gateway	15,696	15,608	21,219	22,084	22,554	22,554	22,554	35.9%	41.5%	44.5%	44.5%	44.5%	12.7%
Southeastern	41,869	40,147	57,450	57,800	66,884	66,884	67,310	43.1%	44.0%	66.6%	66.6%	67.7%	15.0%
VACAR	58,217	56,649	76,712	77,816	79,768	79,768	79,768	35.4%	37.4%	40.8%	40.8%	40.8%	15.0%
SPP	32,636	31,988	49,112	49,535	55,949	58,887	114,728	53.5%	54.9%	74.9%	84.1%	258.7%	13.6%
WECC	111,324	108,535	168,290	173,502	173,502	173,504	173,509	55.1%	59.9%	59.9%	59.9%	59.9%	16.7%
AZ-NM-SNV	18,868	18,176	38,089	38,775	38,775	38,775	38,777	109.6%	113.3%	113.3%	113.3%	113.3%	15.5%
CA-MX US	41,922	40,029	60,278	63,393	63,393	63,393	63,393	50.6%	58.4%	58.4%	58.4%	58.4%	15.9%
NWPP	41,681	41,391	55,850	56,705	56,705	56,710	56,720	34.9%	37.0%	37.0%	37.0%	37.0%	18.4%
RMPA	9,658	9,479	13,712	14,811	14,811	14,811	14,811	44.7%	56.3%	56.3%	56.3%	56.3%	15.4%
Total-U.S.	642,716	622,241	935,694	950,335	971,792	975,820	1,037,025	50.4%	52.7%	56.2%	56.8%	66.7%	15.0%
Canada													
MRO	7,620	7,332	8,715	8,914	8,881	8,894	8,923	18.9%	21.6%	21.1%	21.3%	21.7%	10.0%
NPCC	64,690	62,499	72,293	75,173	76,374	76,374	76,374	15.7%	20.3%	22.2%	22.2%	22.2%	15.0%
Maritimes	5,554	5,113	6,118	6,887	6,887	6,887	6,887	19.7%	34.7%	34.7%	34.7%	34.7%	20.0%
Ontario	22,886	22,886	26,028	28,104	29,326	29,326	29,326	13.7%	22.8%	28.1%	28.1%	28.1%	17.5%
Quebec	36,250	34,500	40,147	40,182	40,161	40,161	40,161	16.4%	16.5%	16.4%	16.4%	16.4%	10.4%
WECC	21,548	21,548	24,389	24,513	24,513	24,513	24,888	13.2%	13.8%	13.8%	13.8%	15.5%	12.5%
Total-Canada	93,858	91,379	105,397	108,600	109,768	109,781	110,185	15.3%	18.8%	20.1%	20.1%	20.6%	10.0%
Mexico													
WECC CA-MX Mex	1,480	1,480	1,930	1,930	1,930	1,930	1,930	30.4%	30.4%	30.4%	30.4%	30.4%	10.1%
Total-NERC	738,054	715,100	1,043,022	1,060,866	1,083,491	1,087,531	1,149,140	45.9%	48.4%	51.5%	52.1%	60.7%	15.0%

Table Margins 2c: Estimated 2013 Summer 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	69,399	68,284	72,204	79,521	79,521	84,617	105,000	5.7%	16.5%	16.5%	23.9%	53.8%	12.5%
FRCC	48,304	44,697	49,330	57,464	57,464	57,464	58,811	10.4%	28.6%	28.6%	28.6%	31.6%	15.0%
MRO	47,500	44,482	49,159	50,218	50,309	54,299	63,612	10.5%	12.9%	13.1%	22.1%	43.0%	15.0%
NPCC	63,445	63,226	73,223	78,207	78,426	78,683	92,524	15.8%	23.7%	24.0%	24.4%	46.3%	15.0%
New England	29,365	29,365	33,478	34,827	35,045	37,122	45,694	14.0%	18.6%	19.3%	26.4%	55.6%	15.0%
New York	34,080	33,861	39,746	43,381	43,381	43,957	46,830	17.4%	28.1%	28.1%	29.8%	38.3%	16.5%
RFC	192,100	183,900	214,000	219,600	221,300	228,502	259,700	16.4%	19.4%	20.3%	24.3%	41.2%	15.0%
RFC-MISO	64,924	63,224	70,714	71,138	72,732	73,544	76,953	11.8%	12.5%	15.0%	16.3%	21.7%	15.4%
RFC-PJM	127,079	120,579	142,022	147,228	147,319	153,732	181,458	17.8%	22.1%	22.2%	27.5%	50.5%	16.2%
SERC	219,712	211,900	240,012	253,404	267,483	267,583	271,933	13.3%	19.6%	26.2%	26.3%	28.3%	15.0%
Central	45,345	42,437	49,607	52,473	53,990	53,990	54,516	16.9%	23.6%	27.2%	27.2%	28.5%	15.0%
Delta	30,187	29,406	36,823	37,499	38,505	38,505	39,043	25.2%	27.5%	30.9%	30.9%	32.8%	15.0%
Gateway	20,144	20,032	23,707	24,834	25,645	25,645	25,645	18.3%	24.0%	28.0%	28.0%	28.0%	12.7%
Southeastern	55,018	53,099	56,306	59,987	68,949	68,949	72,105	6.0%	13.0%	29.8%	29.8%	35.8%	15.0%
VACAR	69,018	66,926	73,569	78,611	80,394	80,494	80,624	9.9%	17.5%	20.1%	20.3%	20.5%	15.0%
SPP	47,255	46,153	49,602	53,477	60,001	63,017	120,430	7.5%	15.9%	30.0%	36.5%	160.9%	13.6%
WECC	150,163	143,988	172,192	204,058	204,058	205,307	207,579	19.6%	41.7%	41.7%	42.6%	44.2%	17.9%
AZ-NM-SNV	32,897	32,060	36,512	39,157	39,157	39,663	41,072	13.9%	22.1%	22.1%	23.7%	28.1%	17.8%
CA-MX US	64,493	60,073	71,622	89,293	89,293	89,293	89,355	19.2%	48.6%	48.6%	48.6%	48.7%	22.3%
NWPP	42,942	42,117	50,768	61,577	61,577	61,664	62,074	20.5%	46.2%	46.2%	46.4%	47.4%	16.3%
RMPA	12,015	11,616	13,853	14,483	14,483	15,131	15,514	19.3%	24.7%	24.7%	30.3%	33.6%	17.1%
Total-U.S.	837,878	806,630	919,722	995,948	1,018,561	1,039,471	1,179,588	14.0%	23.5%	26.3%	28.9%	46.2%	15.0%
Canada													
MRO	7,086	6,826	7,617	8,414	8,414	8,735	9,482	11.6%	23.3%	23.3%	28.0%	38.9%	10.0%
NPCC	48,594	48,154	64,192	72,844	72,977	72,977	73,018	33.3%	51.3%	51.5%	51.5%	51.6%	15.0%
Maritimes	3,502	3,062	6,135	6,948	6,948	6,948	6,948	100.4%	126.9%	126.9%	126.9%	126.9%	20.0%
Ontario	23,092	23,092	26,378	33,054	33,208	33,249	33,249	14.2%	43.1%	43.8%	44.0%	44.0%	19.1%
Quebec	22,000	22,000	31,679	32,842	32,821	32,821	32,821	44.0%	49.3%	49.2%	49.2%	49.2%	11.7%
WECC	19,927	19,927	22,079	23,053	23,053	24,238	26,440	10.8%	15.7%	15.7%	21.6%	32.7%	12.5%
Total-Canada	75,608	74,908	93,888	104,312	104,444	105,950	108,941	25.3%	39.3%	39.4%	41.4%	45.4%	10.0%
Mexico													
WECC CA-MX Mex	2,345	2,345	2,287	2,713	2,713	3,026	3,026	-2.5%	15.7%	15.7%	29.0%	29.0%	15.6%
Total-NERC	915,830	883,882	1,015,897	1,102,973	1,125,718	1,148,448	1,291,554	14.9%	24.8%	27.4%	29.9%	46.1%	15.0%

Table Margins 2d: Estimated 2013/14 Winter 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	47,984	46,869	73,916	81,233	81,233	81,233	106,829	57.7%	73.3%	73.3%	73.3%	127.9%	12.5%
FRCC	47,709	43,813	52,827	62,001	62,001	62,001	63,349	20.6%	41.5%	41.5%	41.5%	44.6%	15.0%
MRO	39,107	37,119	48,197	49,299	50,102	54,092	63,405	29.8%	32.8%	35.0%	45.7%	70.8%	15.0%
NPCC	47,620	47,620	74,107	76,768	77,324	77,324	91,703	55.6%	61.2%	62.4%	62.4%	92.6%	15.0%
New England	22,335	22,335	33,926	35,350	35,906	38,009	46,616	51.9%	58.3%	60.8%	70.2%	108.7%	15.0%
New York	25,285	25,285	40,181	41,418	41,418	41,785	45,087	58.9%	63.8%	63.8%	65.3%	78.3%	16.5%
RFC	155,100	150,200	216,300	221,900	223,600	230,802	262,000	44.0%	47.7%	48.9%	53.7%	74.4%	15.0%
RFC-MISO	51,226	49,601	70,714	71,138	72,732	73,544	76,953	42.6%	43.4%	46.6%	48.3%	55.1%	15.4%
RFC-PJM	103,790	100,925	142,022	147,228	147,319	153,732	181,458	40.7%	45.9%	46.0%	52.3%	79.8%	16.2%
SERC	193,586	187,364	243,169	256,459	272,591	272,591	276,709	29.8%	36.9%	45.5%	45.5%	47.7%	15.0%
Central	44,116	42,324	51,023	53,398	56,556	56,556	56,768	20.6%	26.2%	33.6%	33.6%	34.1%	15.0%
Delta	25,159	24,568	37,783	38,997	40,057	40,057	40,057	53.8%	58.7%	63.0%	63.0%	63.0%	15.0%
Gateway	16,395	16,320	23,607	24,669	25,469	25,469	25,469	44.7%	51.2%	56.1%	56.1%	56.1%	12.7%
Southeastern	45,770	43,839	55,117	58,906	67,909	67,909	71,065	25.7%	34.4%	54.9%	54.9%	62.1%	15.0%
VACAR	62,146	60,313	75,639	80,489	82,600	82,600	83,350	25.4%	33.5%	37.0%	37.0%	38.2%	15.0%
SPP	34,961	34,022	48,991	52,933	59,502	62,541	120,744	44.0%	55.6%	74.9%	83.8%	254.9%	13.6%
WECC	118,280	114,867	167,517	193,056	193,056	194,392	196,632	45.8%	68.1%	68.1%	69.2%	71.2%	16.7%
AZ-NM-SNV	20,661	19,957	38,212	39,719	39,719	40,222	41,553	91.5%	99.0%	99.0%	101.5%	108.2%	15.5%
CA-MX US	43,475	41,162	60,082	80,295	80,295	80,295	80,312	46.0%	95.1%	95.1%	95.1%	95.1%	15.9%
NWPP	44,414	44,076	55,673	57,240	57,240	57,353	57,793	26.3%	29.9%	29.9%	30.1%	31.1%	18.4%
RMPA	10,789	10,529	13,616	15,257	15,257	15,959	16,323	29.3%	44.9%	44.9%	51.6%	55.0%	15.4%
Total-U.S.	684,347	661,874	925,025	993,649	1,019,408	1,034,977	1,181,371	39.8%	50.1%	54.0%	56.4%	78.5%	15.0%
Canada													
MRO	8,405	8,144	8,798	9,815	9,815	10,135	10,883	8.0%	20.5%	20.5%	24.5%	33.6%	10.0%
NPCC	65,553	63,368	72,213	81,117	81,096	81,096	81,153	14.0%	28.0%	28.0%	28.0%	28.1%	15.0%
Maritimes	5,556	5,121	6,266	7,176	7,176	7,176	7,192	22.4%	40.1%	40.1%	40.1%	40.4%	20.0%
Ontario	21,575	21,575	25,708	32,489	32,489	32,530	32,530	19.2%	50.6%	50.6%	50.8%	50.8%	19.1%
Quebec	38,422	36,672	40,239	41,452	41,431	41,431	41,431	9.7%	13.0%	13.0%	13.0%	13.0%	11.7%
WECC	23,431	23,431	24,352	25,335	25,335	26,520	28,722	3.9%	8.1%	8.1%	13.2%	22.6%	12.5%
Total-Canada	97,389	94,943	105,363	116,267	116,246	117,751	120,758	11.0%	22.5%	22.4%	24.0%	27.2%	10.0%
Mexico													
WECC CA-MX Mex	1,636	1,636	1,823	1,854	1,854	2,167	2,167	11.4%	13.3%	13.3%	32.5%	32.5%	10.1%
Total-NERC	783,371	758,453	1,032,211	1,111,769	1,137,508	1,154,895	1,304,295	36.1%	46.6%	50.0%	52.3%	72.0%	15.0%

Table Margins 2e: Estimated 2018 Summer 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	76,134	75,019	72,208	79,525	79,525	84,969	106,745	-3.7%	6.0%	6.0%	13.3%	42.3%	12.5%
FRCC	53,689	49,885	48,005	63,336	63,336	63,336	64,690	-3.8%	27.0%	27.0%	27.0%	29.7%	15.0%
MRO	50,587	47,534	47,484	49,469	49,598	54,317	64,746	-0.1%	4.1%	4.3%	14.3%	36.2%	15.0%
NPCC	66,410	66,191	72,845	78,579	78,798	79,155	95,271	10.1%	18.7%	19.0%	19.6%	43.9%	15.0%
New England	30,960	30,960	33,150	34,499	34,717	37,209	47,441	7.1%	11.4%	12.1%	20.2%	53.2%	15.0%
New York	35,450	35,231	39,696	44,081	44,081	44,777	47,830	12.7%	25.1%	25.1%	27.1%	35.8%	16.5%
RFC	201,300	193,100	214,000	219,800	221,500	230,054	267,900	10.8%	13.8%	14.7%	19.1%	38.7%	15.0%
RFC-MISO	66,650	64,950	70,714	71,138	72,732	74,016	79,461	8.9%	9.5%	12.0%	14.0%	22.3%	15.4%
RFC-PJM	134,524	128,024	142,022	147,368	147,459	154,772	187,144	10.9%	15.1%	15.2%	20.9%	46.2%	16.2%
SERC	237,386	228,862	241,777	262,372	276,673	276,748	290,774	5.6%	14.6%	20.9%	20.9%	27.1%	15.0%
Central	48,597	45,288	49,104	54,410	55,927	55,927	57,061	8.4%	20.1%	23.5%	23.5%	26.0%	15.0%
Delta	32,204	31,438	35,485	36,161	37,167	37,167	40,505	12.9%	15.0%	18.2%	18.2%	28.8%	15.0%
Gateway	20,932	20,817	23,668	24,916	25,727	25,727	25,727	13.7%	19.7%	23.6%	23.6%	23.6%	12.7%
Southeastern	60,602	58,505	61,153	67,860	77,047	77,047	82,853	4.5%	16.0%	31.7%	31.7%	41.6%	15.0%
VACAR	75,051	72,814	72,367	79,025	80,805	80,880	84,628	-0.6%	8.5%	11.0%	11.1%	16.2%	15.0%
SPP	49,696	48,500	49,094	53,319	59,846	62,958	122,231	1.2%	9.9%	23.4%	29.8%	152.0%	13.6%
WECC	163,547	156,938	172,385	207,945	207,945	210,904	215,058	9.8%	32.5%	32.5%	34.4%	37.0%	17.9%
AZ-NM-SNV	37,300	36,382	36,409	43,381	43,381	44,819	47,037	0.1%	19.2%	19.2%	23.2%	29.3%	17.8%
CA-MX US	68,683	63,916	71,597	89,054	89,054	89,054	89,506	12.0%	39.3%	39.3%	39.3%	40.0%	22.3%
NWPP	46,633	45,733	50,984	61,197	61,197	61,678	62,424	11.5%	33.8%	33.8%	34.9%	36.5%	16.3%
RMPA	13,252	12,874	13,853	15,102	15,102	16,146	16,883	7.6%	17.3%	17.3%	25.4%	31.1%	17.1%
Total-U.S.	898,749	866,028	917,798	1,014,345	1,037,220	1,062,441	1,227,414	6.0%	17.1%	19.8%	22.7%	41.7%	15.0%
Canada													
MRO	7,380	7,120	8,695	9,969	9,969	10,290	11,037	22.1%	40.0%	40.0%	44.5%	55.0%	10.0%
NPCC	49,439	49,006	54,035	64,306	64,170	64,170	68,301	10.3%	31.2%	30.9%	30.9%	39.4%	15.0%
Maritimes	3,620	3,187	6,135	6,948	6,948	6,948	6,972	92.5%	118.0%	118.0%	118.0%	118.8%	20.3%
Ontario	22,497	22,497	16,274	23,209	23,094	27,201	27,201	-27.7%	3.2%	2.7%	20.9%	20.9%	20.3%
Quebec	23,322	23,322	31,626	34,149	34,128	34,128	34,128	35.6%	46.4%	46.3%	46.3%	46.3%	11.7%
WECC	22,006	22,006	21,756	22,730	22,730	26,684	28,002	-1.1%	3.3%	3.3%	21.3%	27.2%	12.5%
Total-Canada	78,825	78,132	84,486	97,005	96,869	101,143	107,340	8.1%	24.2%	24.0%	29.5%	37.4%	10.0%
Mexico													
WECC CA-MX Mex	2,650	2,650	2,287	2,788	2,788	3,651	3,651	-13.7%	5.2%	5.2%	37.8%	37.8%	15.6%
Total-NERC	980,224	946,810	1,004,570	1,114,138	1,136,877	1,167,235	1,338,405	6.1%	17.7%	20.1%	23.3%	41.4%	15.0%

Table Margins 2f: Estimated 2018/19 Winter 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	52,405	51,290	73,916	81,233	81,233	81,233	108,453	44.1%	58.4%	58.4%	58.4%	111.4%	12.5%
FRCC	53,065	48,984	51,345	68,087	68,087	68,087	69,441	4.8%	39.0%	39.0%	39.0%	41.8%	15.0%
MRO	41,394	39,320	47,399	49,353	50,157	54,877	65,305	20.5%	25.5%	27.6%	39.6%	66.1%	15.0%
NPCC	48,898	48,898	74,057	76,718	77,274	77,274	93,600	51.5%	56.9%	58.0%	58.0%	91.4%	15.0%
New England	22,860	22,860	33,926	35,350	35,906	38,398	48,563	48.4%	54.6%	57.1%	68.0%	112.4%	15.0%
New York	26,038	26,038	40,131	41,368	41,368	41,735	45,037	54.1%	58.9%	58.9%	60.3%	73.0%	16.5%
RFC	161,600	156,700	216,300	222,100	223,800	232,354	270,200	38.0%	41.7%	42.8%	48.3%	72.4%	15.0%
RFC-MISO	52,985	51,360	70,714	71,138	72,732	74,016	79,461	37.7%	38.5%	41.6%	44.1%	54.7%	15.4%
RFC-PJM	108,525	105,660	142,022	147,368	147,459	154,772	187,144	34.4%	39.5%	39.6%	46.5%	77.1%	16.2%
SERC	206,639	200,181	244,553	260,941	278,873	278,873	291,793	22.2%	30.4%	39.3%	39.3%	45.8%	15.0%
Central	44,894	43,096	51,049	53,424	56,582	56,582	57,433	18.5%	24.0%	31.3%	31.3%	33.3%	15.0%
Delta	27,201	26,618	36,146	37,360	38,420	38,420	40,920	35.8%	40.4%	44.3%	44.3%	53.7%	15.0%
Gateway	17,212	17,137	23,604	24,702	25,502	25,502	25,502	37.7%	44.1%	48.8%	48.8%	48.8%	12.7%
Southeastern	50,298	48,182	59,194	66,009	75,242	75,242	81,048	22.9%	37.0%	56.2%	56.2%	68.2%	15.0%
VACAR	67,034	65,148	74,560	79,446	83,127	83,127	86,890	14.4%	21.9%	27.6%	27.6%	33.4%	15.0%
SPP	37,047	36,028	48,489	52,781	59,354	62,490	122,553	34.6%	46.5%	64.7%	73.4%	240.2%	13.6%
WECC	127,515	124,005	167,813	193,051	193,051	196,122	200,242	35.3%	55.7%	55.7%	58.2%	61.5%	16.7%
AZ-NM-SNV	23,221	22,476	37,055	39,481	39,481	40,958	43,169	64.9%	75.7%	75.7%	82.2%	92.1%	15.5%
CA-MX US	45,926	43,584	59,850	80,530	80,530	80,530	80,937	37.3%	84.8%	84.8%	84.8%	85.7%	15.9%
NWPP	47,639	47,292	56,749	57,687	57,687	58,200	58,961	20.0%	22.0%	22.0%	23.1%	24.7%	18.4%
RMPA	12,038	11,762	13,965	14,704	14,704	15,804	16,523	18.7%	25.0%	25.0%	34.4%	40.5%	15.4%
Total-U.S.	728,563	705,406	923,872	1,004,265	1,031,830	1,051,310	1,221,587	31.0%	42.4%	46.3%	49.0%	73.2%	15.0%
Canada													
MRO	8,789	8,528	9,011	10,399	10,399	10,719	11,467	5.7%	21.9%	21.9%	25.7%	34.5%	10.0%
NPCC	67,266	65,489	61,932	72,405	72,384	72,384	76,485	-5.4%	10.6%	10.5%	10.5%	16.8%	15.0%
Maritimes	5,765	5,338	6,266	7,176	7,176	7,176	7,240	17.4%	34.4%	34.4%	34.4%	35.6%	20.3%
Ontario	20,845	20,845	15,480	22,520	22,520	26,557	26,557	-25.7%	8.0%	8.0%	27.4%	27.4%	20.3%
Quebec	40,656	39,306	40,186	42,709	42,688	42,688	42,688	2.2%	8.7%	8.6%	8.6%	8.6%	11.7%
WECC	25,514	25,514	23,885	25,335	25,335	29,289	30,607	-6.4%	-0.7%	-0.7%	14.8%	20.0%	12.5%
Total-Canada	101,569	99,531	94,828	108,138	108,117	112,392	118,559	-4.7%	8.6%	8.6%	12.9%	19.1%	10.0%
Mexico													
WECC CA-MX Mex	1,842	1,842	2,055	2,054	2,054	2,917	2,917	11.6%	11.5%	11.5%	58.4%	58.4%	10.1%
Total-NERC	831,974	806,779	1,020,755	1,114,457	1,142,001	1,166,619	1,343,063	26.5%	38.1%	41.6%	44.6%	66.5%	15.0%

Notes for Table Margins 2a through 2f

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 DSM 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 United States.

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. The MISO *2009–10 LOLE Study Report* is posted at http://www.midwestmarket.org/publish/Document/62c6cd_120e7409639_-7f2a0a48324a.

Note 10: These tables are arranged by country then Region and subregion. In total, four Interconnections are represented: Eastern, Western, Texas (ERCOT), and Québec (NPCC-Québec). Future assessments will arrange this data by Interconnections.

Estimated Demand, Resources, and Capacity Margins

Capacity Margins for 2009 Long-Term Reliability Assessment Data

Tables 3a through 3f 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 2a through 2f in the *Estimated Demand, Resources, and Reserve Margins* section of this report to facilitate comparison.

Table Margins 3a: Estimated 2009 Summer 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	63,491	62,376	72,204	72,204	72,204	72,204	72,204	13.6%	13.6%	13.6%	13.6%	13.6%	11.1%
FRCC	45,734	42,531	49,239	51,870	51,870	51,870	53,210	13.6%	18.0%	18.0%	18.0%	18.0%	13.0%
MRO	44,206	41,306	49,648	50,308	50,316	51,098	52,925	16.8%	17.9%	17.9%	19.5%	19.2%	13.0%
NPCC	61,327	61,108	73,678	76,671	76,889	77,579	77,647	17.1%	20.3%	20.5%	21.4%	21.2%	13.0%
New England	27,875	27,875	33,475	33,703	33,921	33,921	33,989	16.7%	17.3%	17.8%	17.8%	17.8%	13.0%
New York	33,452	33,233	40,203	42,968	42,968	43,658	43,658	17.3%	22.7%	22.7%	24.3%	23.9%	13.0%
RFC	178,100	169,900	215,700	215,800	217,600	217,904	219,200	21.2%	21.3%	21.9%	22.1%	22.0%	13.0%
RFC-MISO	62,419	60,719	70,714	70,714	72,308	72,308	72,308	14.1%	14.1%	16.0%	16.0%	16.0%	13.0%
RFC-PJM	116,153	109,653	144,837	144,939	145,113	145,422	146,740	24.3%	24.3%	24.4%	24.6%	24.6%	13.0%
SERC	202,738	196,871	242,787	244,008	256,129	256,129	256,433	18.9%	19.3%	23.1%	23.1%	23.1%	13.0%
Central	42,733	40,874	50,660	50,828	51,196	51,196	51,500	19.3%	19.6%	20.2%	20.2%	20.2%	13.0%
Delta	27,865	27,178	38,433	38,466	38,602	38,602	38,602	29.3%	29.3%	29.6%	29.6%	29.6%	13.0%
Gateway	19,065	18,947	20,306	20,306	21,117	21,117	21,117	6.7%	6.7%	10.3%	10.3%	10.3%	13.0%
Southeastern	49,504	47,789	58,745	58,745	67,788	67,788	67,788	18.7%	18.7%	29.5%	29.5%	29.5%	13.0%
VACAR	63,571	62,083	74,643	75,663	77,426	77,426	77,426	16.8%	17.9%	19.8%	19.8%	19.8%	13.0%
SPP	44,463	43,696	49,706	50,127	56,619	59,557	115,398	12.1%	12.8%	22.8%	28.0%	26.6%	13.0%
WECC	140,692	136,441	172,375	174,978	174,978	174,980	174,985	20.8%	22.0%	22.0%	22.0%	22.0%	12.1%
AZ-NM-SNV	30,452	29,843	35,156	35,076	35,076	35,076	35,077	15.1%	14.9%	14.9%	14.9%	14.9%	11.7%
CA-MX US	61,237	58,421	71,447	71,334	71,334	71,334	71,334	18.2%	18.1%	18.1%	18.1%	18.1%	13.3%
NWPP	39,754	39,155	56,001	57,340	57,340	57,342	57,346	30.1%	31.7%	31.7%	31.7%	31.7%	11.9%
RMPA	11,224	10,939	12,815	13,517	13,517	13,517	13,517	14.6%	19.1%	19.1%	19.1%	19.1%	10.5%
Total-U.S.	780,751	754,229	925,336	935,965	956,605	961,322	1,022,001	18.5%	19.4%	21.2%	21.6%	21.5%	13.0%
Canada													
MRO	6,369	6,082	7,372	7,372	7,372	7,385	7,414	17.5%	17.5%	17.5%	17.7%	17.6%	9.0%
NPCC	48,471	48,026	65,078	66,855	67,456	67,456	67,456	26.2%	28.2%	28.8%	28.8%	28.8%	13.0%
Maritimes	3,499	3,054	5,987	5,987	5,987	5,987	5,987	49.0%	49.0%	49.0%	49.0%	49.0%	13.0%
Ontario	24,351	24,351	28,011	29,788	30,410	30,410	30,410	13.1%	18.3%	19.9%	19.9%	19.9%	14.5%
Quebec	20,621	20,621	31,080	31,080	31,059	31,059	31,059	33.7%	33.7%	33.6%	33.6%	33.6%	9.1%
WECC	18,071	18,071	22,099	22,277	22,277	22,277	22,370	18.2%	18.9%	18.9%	18.9%	18.9%	10.2%
Total-Canada	72,911	72,179	94,549	96,504	97,105	97,118	97,240	23.7%	25.2%	25.7%	25.7%	25.7%	13.0%
Mexico													
WECC CA-MX Mex	2,115	2,115	2,446	2,446	2,446	2,446	2,446	13.5%	13.5%	13.5%	13.5%	13.5%	12.5%
Total-NERC	855,777	828,523	1,022,331	1,034,915	1,056,156	1,060,886	1,121,687	19.0%	19.9%	21.6%	22.0%	21.9%	13.0%

Table 3b: Estimated 2009/10 Winter 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	43,463	42,348	73,916	74,797	74,797	74,797	74,797	42.7%	43.4%	43.4%	43.4%	43.4%	11.1%
FRCC	44,446	40,846	52,751	57,216	57,216	57,216	58,556	22.6%	28.6%	28.6%	28.6%	28.6%	13.0%
MRO	36,904	34,985	48,104	48,417	49,165	49,948	51,774	27.3%	27.7%	28.8%	30.4%	30.0%	13.0%
NPCC	47,098	47,098	76,849	77,577	78,092	78,092	78,561	38.7%	39.3%	39.7%	39.7%	39.7%	13.0%
New England	22,100	22,100	36,210	36,545	37,060	37,060	37,529	39.0%	39.5%	40.4%	40.4%	40.4%	13.0%
New York	24,998	24,998	40,639	41,032	41,032	41,032	41,032	38.5%	39.1%	39.1%	39.1%	39.1%	13.0%
RFC	145,800	140,900	218,000	218,100	219,800	220,104	221,400	35.4%	35.4%	35.9%	36.0%	36.0%	13.0%
RFC-MISO	49,051	47,426	70,714	70,714	72,308	72,308	72,308	32.9%	32.9%	34.4%	34.4%	34.4%	13.0%
RFC-PJM	96,644	93,395	144,837	144,939	145,113	145,422	146,740	35.5%	35.6%	35.6%	35.9%	35.8%	13.0%
SERC	181,045	175,541	248,673	251,192	263,272	263,272	263,701	29.4%	30.1%	33.3%	33.3%	33.3%	13.0%
Central	42,240	40,636	52,618	52,785	53,204	53,204	53,207	22.8%	23.0%	23.6%	23.6%	23.6%	13.0%
Delta	23,023	22,501	40,674	40,707	40,862	40,862	40,862	44.7%	44.7%	44.9%	44.9%	44.9%	13.0%
Gateway	15,696	15,608	21,219	22,084	22,554	22,554	22,554	26.4%	29.3%	30.8%	30.8%	30.8%	13.0%
Southeastern	41,869	40,147	57,450	57,800	66,884	66,884	67,310	30.1%	30.5%	40.0%	40.0%	40.0%	13.0%
VACAR	58,217	56,649	76,712	77,816	79,768	79,768	79,768	26.2%	27.2%	29.0%	29.0%	29.0%	13.0%
SPP	32,636	31,988	49,112	49,535	55,949	58,887	114,728	34.9%	35.4%	42.8%	48.1%	45.7%	13.0%
WECC	111,324	108,535	168,290	173,502	173,502	173,504	173,509	35.5%	37.4%	37.4%	37.4%	37.4%	12.1%
AZ-NM-SNV	18,868	18,176	38,089	38,775	38,775	38,775	38,777	52.3%	53.1%	53.1%	53.1%	53.1%	11.7%
CA-MX US	41,922	40,029	60,278	63,393	63,393	63,393	63,393	33.6%	36.9%	36.9%	36.9%	36.9%	13.3%
NWPP	41,681	41,391	55,850	56,705	56,705	56,710	56,720	25.9%	27.0%	27.0%	27.0%	27.0%	11.9%
RMPA	9,658	9,479	13,712	14,811	14,811	14,811	14,811	30.9%	36.0%	36.0%	36.0%	36.0%	10.5%
Total-U.S.	642,716	622,241	935,694	950,335	971,792	975,820	1,037,025	33.5%	34.5%	36.0%	36.4%	36.2%	13.0%
Canada													
MRO	7,620	7,332	8,715	8,914	8,881	8,894	8,923	15.9%	17.7%	17.4%	17.6%	17.6%	9.0%
NPCC	64,690	62,499	72,293	75,173	76,374	76,374	76,374	13.5%	16.9%	18.2%	18.2%	18.2%	13.0%
Maritimes	5,554	5,113	6,118	6,887	6,887	6,887	6,887	16.4%	25.8%	25.8%	25.8%	25.8%	13.0%
Ontario	22,886	22,886	26,028	28,104	29,326	29,326	29,326	12.1%	18.6%	22.0%	22.0%	22.0%	14.5%
Quebec	36,250	34,500	40,147	40,182	40,161	40,161	40,161	14.1%	14.1%	14.1%	14.1%	14.1%	9.1%
WECC	21,548	21,548	24,389	24,513	24,513	24,513	24,888	11.6%	12.1%	12.1%	12.1%	12.1%	10.2%
Total-Canada	93,858	91,379	105,397	108,600	109,768	109,781	110,185	13.3%	15.9%	16.8%	16.8%	16.8%	13.0%
Mexico													
WECC CA-MX Mex	1,480	1,480	1,930	1,930	1,930	1,930	1,930	23.3%	23.3%	23.3%	23.3%	23.3%	12.5%
Total-NERC	738,054	715,100	1,043,022	1,060,866	1,083,491	1,087,531	1,149,140	31.4%	32.6%	34.0%	34.4%	34.2%	13.0%

Table 3c: Estimated 2013 Summer 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	69,399	68,284	72,204	79,521	79,521	84,617	105,000	5.4%	14.1%	14.1%	20.5%	19.3%	11.1%
FRCC	48,304	44,697	49,330	57,464	57,464	57,464	58,811	9.4%	22.2%	22.2%	22.2%	22.2%	13.0%
MRO	47,500	44,482	49,159	50,218	50,309	54,299	63,612	9.5%	11.4%	11.6%	19.5%	18.1%	13.0%
NPCC	63,445	63,226	73,223	78,207	78,426	78,683	92,524	13.7%	19.2%	19.4%	19.7%	19.6%	13.0%
New England	29,365	29,365	33,478	34,827	35,045	37,122	45,694	12.3%	15.7%	16.2%	22.1%	20.9%	13.0%
New York	34,080	33,861	39,746	43,381	43,381	43,957	46,830	14.8%	21.9%	21.9%	23.3%	23.0%	13.0%
RFC	192,100	183,900	214,000	219,600	221,300	228,502	259,700	14.1%	16.3%	16.9%	20.2%	19.5%	13.0%
RFC-MISO	64,924	63,224	70,714	71,138	72,732	73,544	76,953	10.6%	11.1%	13.1%	14.2%	14.0%	13.0%
RFC-PJM	127,079	120,579	142,022	147,228	147,319	153,732	181,458	15.1%	18.1%	18.2%	22.5%	21.6%	13.0%
SERC	219,712	211,900	240,012	253,404	267,483	267,583	271,933	11.7%	16.4%	20.8%	20.8%	20.8%	13.0%
Central	45,345	42,437	49,607	52,473	53,990	53,990	54,516	14.5%	19.1%	21.4%	21.4%	21.4%	13.0%
Delta	30,187	29,406	36,823	37,499	38,505	38,505	39,043	20.1%	21.6%	23.6%	23.6%	23.6%	13.0%
Gateway	20,144	20,032	23,707	24,834	25,645	25,645	25,645	15.5%	19.3%	21.9%	21.9%	21.9%	13.0%
Southeastern	55,018	53,099	56,306	59,987	68,949	68,949	72,105	5.7%	11.5%	23.0%	23.0%	23.0%	13.0%
VACAR	69,018	66,926	73,569	78,611	80,394	80,494	80,624	9.0%	14.9%	16.8%	16.9%	16.9%	13.0%
SPP	47,255	46,153	49,602	53,477	60,001	63,017	120,430	7.0%	13.7%	23.1%	28.1%	26.8%	13.0%
WECC	150,163	143,988	172,192	204,058	204,058	205,307	207,579	16.4%	29.4%	29.4%	30.0%	29.9%	12.1%
AZ-NM-SNV	32,897	32,060	36,512	39,157	39,157	39,663	41,072	12.2%	18.1%	18.1%	19.4%	19.2%	11.7%
CA-MX US	64,493	60,073	71,622	89,293	89,293	89,293	89,355	16.1%	32.7%	32.7%	32.7%	32.7%	13.3%
NWPP	42,942	42,117	50,768	61,577	61,577	61,664	62,074	17.0%	31.6%	31.6%	31.7%	31.7%	11.9%
RMPA	12,015	11,616	13,853	14,483	14,483	15,131	15,514	16.1%	19.8%	19.8%	24.3%	23.2%	10.5%
Total-U.S.	837,878	806,630	919,722	995,948	1,018,561	1,039,471	1,179,588	12.3%	19.0%	20.8%	22.9%	22.4%	13.0%
Canada													
MRO	7,086	6,826	7,617	8,414	8,414	8,735	9,482	10.4%	18.9%	18.9%	22.7%	21.8%	9.0%
NPCC	48,594	48,154	64,192	72,844	72,977	72,977	73,018	25.0%	33.9%	34.0%	34.0%	34.0%	13.0%
Maritimes	3,502	3,062	6,135	6,948	6,948	6,948	6,948	50.1%	55.9%	55.9%	55.9%	55.9%	13.0%
Ontario	23,092	23,092	26,378	33,054	33,208	33,249	33,249	12.5%	30.1%	30.5%	30.6%	30.5%	14.5%
Quebec	22,000	22,000	31,679	32,842	32,821	32,821	32,821	30.6%	33.0%	33.0%	33.0%	33.0%	9.1%
WECC	19,927	19,927	22,079	23,053	23,053	24,238	26,440	9.7%	13.6%	13.6%	18.7%	17.8%	10.2%
Total-Canada	75,608	74,908	93,888	104,312	104,444	105,950	108,941	20.2%	28.2%	28.3%	29.7%	29.3%	13.0%
Mexico													
WECC CA-MX Mex	2,345	2,345	2,287	2,713	2,713	3,026	3,026	-2.5%	13.6%	13.6%	25.1%	22.5%	12.5%
Total-NERC	915,830	883,882	1,015,897	1,102,973	1,125,718	1,148,448	1,291,554	13.0%	19.9%	21.5%	23.5%	23.0%	13.0%

Table 3d: Estimated 2013/14 Winter 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	47,984	46,869	73,916	81,233	81,233	81,233	106,829	36.6%	42.3%	42.3%	42.3%	42.3%	11.1%
FRCC	47,709	43,813	52,827	62,001	62,001	62,001	63,349	17.1%	29.3%	29.3%	29.3%	29.3%	13.0%
MRO	39,107	37,119	48,197	49,299	50,102	54,092	63,405	23.0%	24.7%	25.9%	33.9%	31.4%	13.0%
NPCC	47,620	47,620	74,107	76,768	77,324	77,324	91,703	35.7%	38.0%	38.4%	38.4%	38.4%	13.0%
New England	22,335	22,335	33,926	35,350	35,906	38,009	46,616	34.2%	36.8%	37.8%	43.7%	41.2%	13.0%
New York	25,285	25,285	40,181	41,418	41,418	41,785	45,087	37.1%	39.0%	39.0%	39.8%	39.5%	13.0%
RFC	155,100	150,200	216,300	221,900	223,600	230,802	262,000	30.6%	32.3%	32.8%	36.0%	34.9%	13.0%
RFC-MISO	51,226	49,601	70,714	71,138	72,732	73,544	76,953	29.9%	30.3%	31.8%	32.9%	32.6%	13.0%
RFC-PJM	103,790	100,925	142,022	147,228	147,319	153,732	181,458	28.9%	31.4%	31.5%	35.8%	34.4%	13.0%
SERC	193,586	187,364	243,169	256,459	272,591	272,591	276,709	22.9%	26.9%	31.3%	31.3%	31.3%	13.0%
Central	44,116	42,324	51,023	53,398	56,556	56,556	56,768	17.0%	20.7%	25.2%	25.2%	25.2%	13.0%
Delta	25,159	24,568	37,783	38,997	40,057	40,057	40,057	35.0%	37.0%	38.7%	38.7%	38.7%	13.0%
Gateway	16,395	16,320	23,607	24,669	25,469	25,469	25,469	30.9%	33.8%	35.9%	35.9%	35.9%	13.0%
Southeastern	45,770	43,839	55,117	58,906	67,909	67,909	71,065	20.5%	25.6%	35.4%	35.4%	35.4%	13.0%
VACAR	62,146	60,313	75,639	80,489	82,600	82,600	83,350	20.3%	25.1%	27.0%	27.0%	27.0%	13.0%
SPP	34,961	34,022	48,991	52,933	59,502	62,541	120,744	30.6%	35.7%	42.8%	47.9%	45.6%	13.0%
WECC	118,280	114,867	167,517	193,056	193,056	194,392	196,632	31.4%	40.5%	40.5%	41.2%	40.9%	12.1%
AZ-NM-SNV	20,661	19,957	38,212	39,719	39,719	40,222	41,553	47.8%	49.8%	49.8%	51.0%	50.4%	11.7%
CA-MX US	43,475	41,162	60,082	80,295	80,295	80,295	80,312	31.5%	48.7%	48.7%	48.7%	48.7%	13.3%
NWPP	44,414	44,076	55,673	57,240	57,240	57,353	57,793	20.8%	23.0%	23.0%	23.2%	23.2%	11.9%
RMPA	10,789	10,529	13,616	15,257	15,257	15,959	16,323	22.7%	31.0%	31.0%	35.6%	34.0%	10.5%
Total-U.S.	684,347	661,874	925,025	993,649	1,019,408	1,034,977	1,181,371	28.4%	33.4%	35.1%	36.6%	36.0%	13.0%
Canada													
MRO	8,405	8,144	8,798	9,815	9,815	10,135	10,883	7.4%	17.0%	17.0%	20.3%	19.6%	9.0%
NPCC	65,553	63,368	72,213	81,117	81,096	81,096	81,153	12.2%	21.9%	21.9%	21.9%	21.9%	13.0%
Maritimes	5,556	5,121	6,266	7,176	7,176	7,176	7,192	18.3%	28.6%	28.6%	28.6%	28.6%	13.0%
Ontario	21,575	21,575	25,708	32,489	32,489	32,530	32,530	16.1%	33.6%	33.6%	33.7%	33.7%	14.5%
Quebec	38,422	36,672	40,239	41,452	41,431	41,431	41,431	8.9%	11.5%	11.5%	11.5%	11.5%	9.1%
WECC	23,431	23,431	24,352	25,335	25,335	26,520	28,722	3.8%	7.5%	7.5%	12.2%	11.6%	10.2%
Total-Canada	97,389	94,943	105,363	116,267	116,246	117,751	120,758	9.9%	18.3%	18.3%	19.6%	19.4%	13.0%
Mexico													
WECC CA-MX Mex	1,636	1,636	1,823	1,854	1,854	2,167	2,167	10.3%	11.8%	11.8%	28.6%	24.5%	12.5%
Total-NERC	783,371	758,453	1,032,211	1,111,769	1,137,508	1,154,895	1,304,295	26.5%	31.8%	33.3%	34.9%	34.3%	13.0%

Table 3e: Estimated 2018 Summer 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	76,134	75,019	72,208	79,525	79,525	84,969	106,745	-3.9%	5.7%	5.7%	12.5%	11.7%	11.1%
FRCC	53,689	49,885	48,005	63,336	63,336	63,336	64,690	-3.9%	21.2%	21.2%	21.2%	21.2%	13.0%
MRO	50,587	47,534	47,484	49,469	49,598	54,317	64,746	-0.1%	3.9%	4.2%	13.7%	12.5%	13.0%
NPCC	66,410	66,191	72,845	78,579	78,798	79,155	95,271	9.1%	15.8%	16.0%	16.5%	16.4%	13.0%
New England	30,960	30,960	33,150	34,499	34,717	37,209	47,441	6.6%	10.3%	10.8%	18.0%	16.8%	13.0%
New York	35,450	35,231	39,696	44,081	44,081	44,777	47,830	11.2%	20.1%	20.1%	21.7%	21.3%	13.0%
RFC	201,300	193,100	214,000	219,800	221,500	230,054	267,900	9.8%	12.1%	12.8%	16.7%	16.1%	13.0%
RFC-MISO	66,650	64,950	70,714	71,138	72,732	74,016	79,461	8.2%	8.7%	10.7%	12.5%	12.2%	13.0%
RFC-PJM	134,524	128,024	142,022	147,368	147,459	154,772	187,144	9.9%	13.1%	13.2%	18.1%	17.3%	13.0%
SERC	237,386	228,862	241,777	262,372	276,673	276,748	290,774	5.3%	12.8%	17.3%	17.3%	17.3%	13.0%
Central	48,597	45,288	49,104	54,410	55,927	55,927	57,061	7.8%	16.8%	19.0%	19.0%	19.0%	13.0%
Delta	32,204	31,438	35,485	36,161	37,167	37,167	40,505	11.4%	13.1%	15.4%	15.4%	15.4%	13.0%
Gateway	20,932	20,817	23,668	24,916	25,727	25,727	25,727	12.0%	16.5%	19.1%	19.1%	19.1%	13.0%
Southeastern	60,602	58,505	61,153	67,860	77,047	77,047	82,853	4.3%	13.8%	24.1%	24.1%	24.1%	13.0%
VACAR	75,051	72,814	72,367	79,025	80,805	80,880	84,628	-0.6%	7.9%	9.9%	10.0%	10.0%	13.0%
SPP	49,696	48,500	49,094	53,319	59,846	62,958	122,231	1.2%	9.0%	19.0%	24.2%	23.0%	13.0%
WECC	163,547	156,938	172,385	207,945	207,945	210,904	215,058	9.0%	24.5%	24.5%	26.0%	25.6%	12.1%
AZ-NM-SNV	37,300	36,382	36,409	43,381	43,381	44,819	47,037	0.1%	16.1%	16.1%	19.4%	18.8%	11.7%
CA-MX US	68,683	63,916	71,597	89,054	89,054	89,054	89,506	10.7%	28.2%	28.2%	28.2%	28.2%	13.3%
NWPP	46,633	45,733	50,984	61,197	61,197	61,678	62,424	10.3%	25.3%	25.3%	26.1%	25.9%	11.9%
RMPA	13,252	12,874	13,853	15,102	15,102	16,146	16,883	7.1%	14.8%	14.8%	21.7%	20.3%	10.5%
Total-U.S.	898,749	866,028	917,798	1,014,345	1,037,220	1,062,441	1,227,414	5.6%	14.6%	16.5%	18.9%	18.5%	13.0%
Canada													
MRO	7,380	7,120	8,695	9,969	9,969	10,290	11,037	18.1%	28.6%	28.6%	31.8%	30.8%	9.0%
NPCC	49,439	49,006	54,035	64,306	64,170	64,170	68,301	9.3%	23.8%	23.6%	23.6%	23.6%	13.0%
Maritimes	3,620	3,187	6,135	6,948	6,948	6,948	6,972	48.1%	54.1%	54.1%	54.1%	54.1%	13.0%
Ontario	22,497	22,497	16,274	23,209	23,094	27,201	27,201	-38.2%	3.1%	2.6%	20.4%	17.3%	14.5%
Quebec	23,322	23,322	31,626	34,149	34,128	34,128	34,128	26.3%	31.7%	31.7%	31.7%	31.7%	9.1%
WECC	22,006	22,006	21,756	22,730	22,730	26,684	28,002	-1.1%	3.2%	3.2%	20.6%	17.5%	10.2%
Total-Canada	78,825	78,132	84,486	97,005	96,869	101,143	107,340	7.5%	19.5%	19.3%	23.8%	22.8%	13.0%
Mexico													
WECC CA-MX Mex	2,650	2,650	2,287	2,788	2,788	3,651	3,651	-15.9%	4.9%	4.9%	35.9%	27.4%	12.5%
Total-NERC	980,224	946,810	1,004,570	1,114,138	1,136,877	1,167,235	1,338,405	5.7%	15.0%	16.7%	19.4%	18.9%	13.0%

Table 3f: Estimated 2018/19 Winter 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)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	52,405	51,290	73,916	81,233	81,233	81,233	108,453	30.6%	36.9%	36.9%	36.9%	36.9%	11.1%
FRCC	53,065	48,984	51,345	68,087	68,087	68,087	69,441	4.6%	28.1%	28.1%	28.1%	28.1%	13.0%
MRO	41,394	39,320	47,399	49,353	50,157	54,877	65,305	17.0%	20.3%	21.6%	31.0%	28.3%	13.0%
NPCC	48,898	48,898	74,057	76,718	77,274	77,274	93,600	34.0%	36.3%	36.7%	36.7%	36.7%	13.0%
New England	22,860	22,860	33,926	35,350	35,906	38,398	48,563	32.6%	35.3%	36.3%	43.3%	40.5%	13.0%
New York	26,038	26,038	40,131	41,368	41,368	41,735	45,037	35.1%	37.1%	37.1%	37.9%	37.6%	13.0%
RFC	161,600	156,700	216,300	222,100	223,800	232,354	270,200	27.6%	29.4%	30.0%	33.8%	32.6%	13.0%
RFC-MISO	52,985	51,360	70,714	71,138	72,732	74,016	79,461	27.4%	27.8%	29.4%	31.2%	30.6%	13.0%
RFC-PJM	108,525	105,660	142,022	147,368	147,459	154,772	187,144	25.6%	28.3%	28.3%	33.3%	31.7%	13.0%
SERC	206,639	200,181	244,553	260,941	278,873	278,873	291,793	18.1%	23.3%	28.2%	28.2%	28.2%	13.0%
Central	44,894	43,096	51,049	53,424	56,582	56,582	57,433	15.6%	19.3%	23.8%	23.8%	23.8%	13.0%
Delta	27,201	26,618	36,146	37,360	38,420	38,420	40,920	26.4%	28.8%	30.7%	30.7%	30.7%	13.0%
Gateway	17,212	17,137	23,604	24,702	25,502	25,502	25,502	27.4%	30.6%	32.8%	32.8%	32.8%	13.0%
Southeastern	50,298	48,182	59,194	66,009	75,242	75,242	81,048	18.6%	27.0%	36.0%	36.0%	36.0%	13.0%
VACAR	67,034	65,148	74,560	79,446	83,127	83,127	86,890	12.6%	18.0%	21.6%	21.6%	21.6%	13.0%
SPP	37,047	36,028	48,489	52,781	59,354	62,490	122,553	25.7%	31.7%	39.3%	44.6%	42.3%	13.0%
WECC	127,515	124,005	167,813	193,051	193,051	196,122	200,242	26.1%	35.8%	35.8%	37.4%	36.8%	12.1%
AZ-NM-SNV	23,221	22,476	37,055	39,481	39,481	40,958	43,169	39.3%	43.1%	43.1%	46.8%	45.1%	11.7%
CA-MX US	45,926	43,584	59,850	80,530	80,530	80,530	80,937	27.2%	45.9%	45.9%	45.9%	45.9%	13.3%
NWPP	47,639	47,292	56,749	57,687	57,687	58,200	58,961	16.7%	18.0%	18.0%	18.9%	18.7%	11.9%
RMPA	12,038	11,762	13,965	14,704	14,704	15,804	16,523	15.8%	20.0%	20.0%	27.5%	25.6%	10.5%
Total-U.S.	728,563	705,406	923,872	1,004,265	1,031,830	1,051,310	1,221,587	23.6%	29.8%	31.6%	33.5%	32.9%	13.0%
Canada													
MRO	8,789	8,528	9,011	10,399	10,399	10,719	11,467	5.4%	18.0%	18.0%	21.1%	20.4%	9.0%
NPCC	67,266	65,489	61,932	72,405	72,384	72,384	76,485	-5.7%	9.6%	9.5%	9.5%	9.5%	13.0%
Maritimes	5,765	5,338	6,266	7,176	7,176	7,176	7,240	14.8%	25.6%	25.6%	25.6%	25.6%	13.0%
Ontario	20,845	20,845	15,480	22,520	22,520	26,557	26,557	-34.7%	7.4%	7.4%	25.4%	21.5%	14.5%
Quebec	40,656	39,306	40,186	42,709	42,688	42,688	42,688	2.2%	8.0%	7.9%	7.9%	7.9%	9.1%
WECC	25,514	25,514	23,885	25,335	25,335	29,289	30,607	-6.8%	-0.7%	-0.7%	14.9%	12.9%	10.2%
Total-Canada	101,569	99,531	94,828	108,138	108,117	112,392	118,559	-5.0%	8.0%	7.9%	11.9%	11.4%	13.0%
Mexico													
WECC CA-MX Mex	1,842	1,842	2,055	2,054	2,054	2,917	2,917	10.4%	10.3%	10.3%	52.3%	36.9%	12.5%
Total-NERC	831,974	806,779	1,020,755	1,114,457	1,142,001	1,166,619	1,343,063	21.0%	27.6%	29.4%	31.5%	30.8%	13.0%

Transmission and Transformer Tables

Under Construction and Planned Transmission > 200 kV

Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
ERCOT					
Bell County East	TNP One	88.0	300-399	1631	May-11
Divide	Twin Buttes	31.0	300-399	1707	Sep-11
Gilleland	Techridge	8.0	300-399	710	Jun-12
Hutto Switch	Salado Switch	73.8	300-399	1631	Jun-10
Jacksboro Switch	Willow Creek	21.0	300-399	2987	Dec-10
Killeen switch	Salado Switch	15.7	300-399	1072	Jun-10
Krum W. Switch	NW Carrollton	54.7	300-399	1631	Jun-11
Krum W. Switch	Anna Switch	100.0	300-399	710	May-15
Riley	Bowman	42.0	300-399	2724	Sep-11
San Miguel	Lobo	44.0	300-399	1623	Apr-10
Twin Buttes	Coleman/Brown County Line	88.0	300-399	1631	Sep-11
Willow Creek	Parker	22.6	300-399	2987	Dec-10
Zorn	Clear Springs-Gilleland Creek Hutto Switch	165.0	300-399	1630	Dec-11
SWEETWTR	TONKAWAS	19.0	300-399	5976	Dec-13
PARKER_5	WILLOWCK	19.0	300-399	5976	Dec-13
EVRMAN_E	PARKER_5	110.0	300-399	3262	Dec-13
OKLAEHV7	BOWMAN_5	38.0	300-399	3262	Dec-13
GILLES5	L_KENDAL	20.0	300-399	1631	Dec-13
NEWTON	KILL_SS_	27.0	300-399	1631	Dec-13
NEWTON	GILLES5	83.0	300-399	1631	Dec-13
CRZ_PHAB	CRZ_PHAA	25.0	300-399	1631	Dec-13
CRZ_PHAC	CRZ_PHAA	25.0	300-399	1631	Dec-13
CRZ_PHAD	CRZ_PHAC	56.0	300-399	3262	Dec-13
CRZ_PHBA	CRZ_PHAB	60.0	300-399	1631	Dec-13
CRZ_PHBA	CRZ_PHAC	56.0	300-399	3262	Dec-13
CRZ_PHBB	OKLAEHV7	150.0	300-399	1631	Dec-13
CRZ_PHBB	CRZ_PHBA	38.0	300-399	3262	Dec-13
CRZ_MCCA	ODESEHV_	50.0	300-399	2988	Dec-13
CRZ_MCCC	CRZ_MCCA	14.0	300-399	1631	Dec-13
CRZ_MCCD	L_TWINBU	33.0	300-399	2988	Dec-13
CRZ_MCCD	L_KENDAL	138.0	300-399	5976	Dec-13
CRZ_MCCC	CRZ_MCCD	88.0	300-399	1631	Dec-13
CRZ_CENA	TONKAWAS	44.0	300-399	5976	Dec-13
CRZ_CENA	CRZ_CENC	75.0	300-399	5976	Dec-13
CRZ_CENB	WILLOWCK	169.0	300-399	5976	Dec-13
CRZ_CENB	CRZ_PHAD	69.0	300-399	3262	Dec-13
CRZ_CENB	CRZ_CENA	12.0	300-399	5976	Dec-13
CRZ_WESTC	ODESEHV	44.0	300-399	3262	Dec-13
CRZ_WESTA	CRZ_CENA	47.0	300-399	3262	Dec-13
CRZ_WESTA	CRZ_WESTC	33.0	300-399	1631	Dec-13
CRZ_WESTA	CRZ_CEND	57.0	300-399	1631	Dec-13

Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
CRZ_WESTB	MOSS_8	6.0	300-399	717	Dec-13
CRZ_CENE	CRZ_CEND	27.0	300-399	1631	Dec-13
CRZ_CBLUFF	SWEETWTR	25.0	300-399	5976	Dec-13
PANOAKMI	OKLAEHV7	62.0	300-399	3262	Dec-13
PANOAKMI	CRZ_PHAC	105.0	300-399	1631	Dec-13
PANOAKMI	CRZ_PHAD	38.0	300-399	3262	Dec-13
PANOAKMI	CRZ_CENC	117.0	300-399	5976	Dec-13
WESTKRUM	W_DENT_5	19.0	300-399	1631	Dec-13
WESTKRUM	JACKSBRO	43.0	300-399	1631	Dec-13
WESTKRUM	CRLTN_NW	60.0	300-399	5976	Dec-13
WESTKRUM	ANNASW_5	44.0	300-399	5976	Dec-13
WESTKRUM	OKLAEHV7	106.0	300-399	5976	Dec-13
NAVARRO	CRZ_CENC	174.0	300-399	2988	Dec-13
BROWN	SALADOSS	88.0	300-399	1631	Dec-13
BROWN	L_TWINBU	106.0	300-399	5976	Dec-13
BROWN	NEWTON	41.3	300-399	2988	Dec-13
HICKS	WILLOWCK	31.0	300-399	5976	Dec-13
TESLA	OKLAEHV7	60.0	300-399	1631	Dec-13
TESLA	CRZ_PHAC	75.0	300-399	1631	Dec-13
TESLA	CRZ_PHBB	115.0	300-399	1631	Dec-13
TESLA	PANOAKMI	35.0	300-399	2988	Dec-13
BLUF_CRK	CRZ_CBluf	6.0	300-399	5976	Dec-13
BLUF_CRK	BROWN	75.0	300-399	5976	Dec-13
L_DIVIDE	CRZ_CEND	36.0	300-399	1631	Dec-13
SAMSWITC	CRZ_CENC	148.0	300-399	2988	Dec-13
L_DIVIDE	L_TWINBU	30.9	300-399	3262	Dec-13
JACKSBRO	WILLOWCK	21.0	300-399	2988	Dec-13
JACKSBRO	BOWMAN_5	45.9	300-399	1920	Dec-13
PARKER_5	WILLOWCK	22.6	300-399	2988	Dec-13
FRCC					
Bartow	Northeast Circuit 1	4.0	200-299	612	03-2009
Bartow	Northeast Circuit 2	4.0	200-299	612	03-2009
Bartow	Northeast Circuit 3	4.0	200-299	612	03-2009
St. Johns	Pringle	25.0	200-299	759	06-2009
Northeast	40th Street	8.0	200-299	810	06-2009
Pasadena	51st Street	1.0	200-299	810	06-2009
51st Street	40th Street	1.0	200-299	810	06-2009
Avon Park	Fort Meade	26.0	200-299	837	06-2009
Big Bend	Big Bend (CT 4)	0.1	200-299	460	10-2009
Avalon	Gifford	8.0	200-299	1195	12-2009
Intercession City	West Lake Wales #1	30.0	200-299	1195	06-2010
Intercession City	West Lake Wales #2	30.0	200-299	1195	06-2010
Bithlo	Stanton (OUC)	6.0	200-299	1141	06-2010
Stanton	Bithlo (PEF tie point)	4.4	200-299	800	05-2010
Manatee	BobWhite	30.0	200-299	1190	12-2012
Hines Energy Complex	West Lake Wales #2	21.0	200-299	925	05-2012
Big Bend	Big Bend (CT 5, 6, 7)	0.1	200-299	478	06-2012
Hopkins-Crawfordville	SUB 5 230	10.0	200-299	464	06-2012
Polk Power Station	Polk (CT 6, 7, and 8)	0.7	200-299	650	12-2012
Gilchrist Generating Station	Gilchrist Switching Station	10.0	200-299	1195	12-2015

Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
Gilchrist Generating Station	Gilchrist Switching Station	10.0	200-299	1195	05-2016
SUB 5 230	SUB 7 230	13.0	200-299	464	06-2016
Kathleen	Lake Tarpon	45.0	200-299	1195	06-2016
Levy	Central FL South	50.0	400-599	2870	06-2016
Levy	Crystal River	10.0	400-599	2870	06-2016
Levy	Citrus #1	10.0	400-599	2870	06-2016
Levy	Citrus #2	10.0	400-599	2870	06-2016
Crystal River	Brookridge	35.0	200-299	1195	06-2016
Brookridge	Brooksville West	4.0	200-299	1195	06-2016
MRO					
Gardner Park	Highway 22	55.0	300-399	1425	01-2010
Morgan	Highway 22	27.0	300-399	1425	01-2010
Werner West	Highway 22	24.0	300-399	1425	01-2010
Paddock	Rockdale	30.3	300-399	1348	06-2010
Rockdale	West Middleton	32.4	300-399	1195	06-2013
Belfield (BN)	Rhame, ND (New)	74.0	200-299	Unknown	12-2009
Williston, ND (New)	Rhame (New)	50.0	200-299	Unknown	12-2009
Broadland (BD)	Storla (ST)	40.0	200-299	Unknown	12-2015
Brookings, SD	Twin Cities, MN	230.0	300-399	1000	01-2015
Brookings	Lyon County	48.0	300-399	2056	04-2014
Lyon County	Minnesota Valley	30.0	300-399	2056	04-2014
Lyon County	Helena	114.0	300-399	4112	04-2014
Monticello	Quarry	30.0	300-399	2056	10-2011
Quarry	Alexandria	70.0	300-399	2056	04-2013
Bemidji	Boswell	68.0	200-299	439	04-2011
Helena	Lake Marion	16.0	300-399	2056	04-2013
Lake Marion	Hampton	18.0	300-399	2056	04-2013
Salem	Hazleton	27.0	300-399	1195	12-2011
Salem	Hazleton	54.0	300-399	1195	12-2011
Bemidji	Boswell	69.0	200-299	465	07-2012
Monticello	Quary	35.0	300-399	2050	09-2011
Quary	Alexandria Switching Station	70.0	300-399	2050	09-2013
Alexandria SS	Bison	135.0	300-399	2050	06-2015
Boswell	Essar taconite Plant	10.0	200-299	465	09-2011
Essar taconite Plant	Essar Steel Plant	2.0	200-299	465	02-2011
Essar Steel Plant	Shannon	8.0	200-299	465	12-2011
Essar Steel Plant	Blackberry	18.0	200-299	465	02-2011
NW68th&Holdrege	Columbus East	38.0	300-399	1195	06-2009
NW68th&Holdrege	Columbus East	29.0	300-399	1195	06-2009
Columbus East	Shell Creek	11.0	300-399	1195	06-2009
Columbus East	Shell Creek	1.0	300-399	1195	06-2009
Henday	Conawapa Constr Power	18.0	200-299	768.8	10-2013
Dorsey	Portage	44.0	200-299	564.5	10-2014
Conawapa	Riel	833.0	400-599	2000	10-2017
Conawapa	Henday	18.0	200-299	768.8	10-2017
Conawapa	Henday	18.0	200-299	768.8	10-2017
Conawapa	Henday	18.0	200-299	768.8	10-2017
Long Spruce	Conawapa	35.0	200-299	1029.2	10-2017
LaVerendrye	St Vital	21.0	200-299	658.1	10-2017
Poplar River	Pasqua	100.0	200-299	765	03-2010

	Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
	Belfield	Rhame	45.0	200-299	0	09-2009
	Fort Peck	Williston	0.0	200-299	0	12-2015
NPCC						
New England	West Amesbury	394 Tap	0.1	300-399	2154	09-2009
New England	Wakefield Jct.	339 Tap	0.1	300-399	2172	11-2009
New England	Vernon	Newfane	18.0	300-399	1200	06-2011
New England	Newfane	Coolidge	35.0	300-399	1200	06-2011
New England	West Farnum	CT/RI Border	17.7	300-399	2172	07-2012
New England	Millbury	West Farnum	20.7	300-399	2172	11-2012
New England	Kent County	West Farnum	21.4	300-399	1545	06-2013
New England	Card	Lake Road	29.3	300-399	2420	12-2013
New England	Lake Road	CT/RI Border	7.6	300-399	2420	12-2013
New England	Frost Bridge	North Bloomfield S/S	35.4	300-399	2420	12-2013
New England	North Bloomfield	CT/MA Border	11.9	300-399	2420	12-2013
New England	Agawam	CT/MA Border	6.0	300-399	2420	12-2013
New England	Agawam	Ludlow S/S	16.8	300-399	2420	12-2015
New England	MPRP	Surowiec	184.0	300-399	2067	12-2012
New England	Sandwich	Carver	17.9	300-399	2170	12-2012
NY	Avoca	Stony Ridge	0.0	200-299	478	07-2011
NY	Stony Ridge	Hillside	0.0	200-299	478	07-2011
NY	PSE&G 230 kV	Goethals 345 kV - Linden Cogen	0.0	300-399	179	07-2010
Ontario	Claireville TS	Richview TS	6.0	200-299	561	05-2009
Ontario	Cardiff TS	Hurontario TS	5.0	200-299	1072	06-2009
Ontario	Hawthorne TS	Outaouais	26.0	200-299	881	06-2009
Ontario	Essa TS	Stayner TS	33.0	200-299	740	07-2009
Ontario	Hurontario TS	Jim Yarrow TS	4.0	200-299	740	11-2009
Ontario	Ingersoll TS	Kam TS	15.0	200-299	964	04-2010
Ontario	Allanburg TS	Middleport TS	93.0	200-299	964	On-Hold
Ontario	Bruce Complex	Milton TS	218.0	400-599	5656	12-2011
Québec	Les Mechins	Line 23YY	2.4	200-299	200	12-2009
Québec	Chenier	Outaouais	70.6	300-399	4400	05-2010
Québec	Eastmain-1A	Eastmain-1	1.2	300-399	1635	07-2010
Québec	Sarcelle	Eastmain-1	68.8	300-399	818	07-2010
Québec	Goemon	Mont-Louis	46.3	200-299	231	12-2010
Québec	Goemon	Gros-Morne	55.6	200-299	231	12-2011
Québec	Romaine-2	Arnaud	162.9	300-399	3270	12-2014
Québec	Romaine-1	Romaine-2	19.1	300-399	1635	12-2016
Québec	Tap circuit 3090	Lac Alfred	13.0	300-399	TBD	09-2012
Québec	Tap circuit 3089	Le Plateau	0.6	300-399	TBD	09-2011
Québec	Tap circuit 3001	Seigneurie 2	7.8	300-399	TBD	09-2013
Québec	Tap circuit 2373	Des Moulins	4.4	200-299	TBD	09-2011
Québec	Tap circuit	Bas St-Laurent	0.6	200-299	TBD	09-2012
Québec	Tap circuit	New Richmond	4.3	200-299	TBD	09-2012
Québec	Tap circuit	Clermont	5.7	300-399	TBD	09-2015
RFC						
	Amos	Welton Spring	180.0	600+	TBD	12-2013
	Welton Spring	Kemptown	105.0	600+	TBD	12-2013
	Meadowbrook	Loudoun	26.0	400-599	TBD	12-2011
	Mt. Storm	502 Junction	60.0	400-599	TBD	12-2011

Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
Mt. Storm	Meadowbrook	59.3	400-599	TBD	12-2011
Prexy	502 Junction	20.0	400-599	TBD	12-2011
Orchard	Cumberland	15.0	200-299	TBD	12-2009
Sporn	Waterford	9.0	300-399	TBD	12-2010
Doubs	Monocacy	15.0	200-299	TBD	12-2009
North Longview	Fort Martin	2.0	400-599	TBD	12-2009
Calvert Cliffs	Calvert Cliffs (new)	1.0	400-599	TBD	12-2015
Raphael Road	Bagley	5.9	200-299	TBD	12-2014
Cayuga Ridge South	Wilton Center	10.0	300-399	TBD	12-2009
Arsenal	Logans Ferry	12.0	300-399	TBD	12-2010
Brunot Island	Arsenal	6.4	300-399	TBD	12-2010
Brady	Carson	1.5	300-399	TBD	01-2012
Collier	Brunot Island	7.2	300-399	TBD	07-2010
Brunot Island	Brady	5.0	300-399	TBD	01-2012
Crescent	Brunot Island	17.1	300-399	TBD	12-2009
Calvert Cliffs	Vienna	35.0	400-599	1828	04-2012
Vienna	Indian River	35.1	400-599	1828	04-2012
Indian River	Salem	80.0	400-599	1828	04-2014
Loretto	Piney Grove	6.0	200-299	TBD	05-2013
Piney Grove	Mt. Olive	6.0	200-299	TBD	08-2012
Vienna	Sharptown	12.0	200-299	TBD	03-2011
Vienna	Loretto	16.0	200-299	TBD	05-2013
Chamberlin	Hanna	26.0	300-399	1380/1646	01-2012
Hanna	Mansfield	52.0	300-399	1380/1646	01-2012
Allen Junction	Fulton	14.6	300-399	1370/1646	01-2012
Fulton	Midway	24.3	300-399	1370/1646	01-2012
Cranberry	Cabot	40.0	400-599	2800/3600	01-2012
Cranberry	Wylie Ridge	40.0	400-599	2800/3600	01-2012
Bismarck	Troy	13.9	300-399	700	08-2011
Whitpain	Center Point	0.0	400-599	2555	01-2010
Center Point	Elroy	0.0	400-599	2555	01-2010
Perkiomen	Center Point	0.0	200-299	1245	01-2010
Center Point	North Wales	0.0	200-299	1245	01-2010
Delta (IPP P04)	Peach Bottom	4.0	400-599	TBD	01-2010
Burtonsville	Sandy Spring	12.0	200-299	TBD	09-2010
Calvert Cliffs	Salem	45.0	400-599	TBD	05-2013
Possum Point	Calvert Cliffs	24.0	400-599	TBD	05-2013
Richie	Benning	2.0	200-299	TBD	01-2012
Brunner Island	West Shore	16.0	200-299	653	04-2013
Susquehanna	Roseland	146.0	400-599	3005	09-2012
Montville	Jefferson	15.1	400-599	3005	01-2012
Jefferson	Bushkill	22.3	400-599	3005	01-2012
Bergen	Marion	10.2	200-299	TBD	05-2013
Branchburg	Flagtown	4.0	200-299	TBD	12-2009
Branchburg	Roseland	29.9	400-599	TBD	05-2013
Roseland	Kearny	22.0	200-299	TBD	04-2011
Roseland	Hudson	20.0	400-599	TBD	05-2013
Sewaren	Woodbridge	3.4	200-299	TBD	05-2013
Gibson	Brown	37.0	300-399	1400	02-2010
Reid	Brown	24.5	300-399	1400	04-2011

	Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
SERC						
Central	Brown North	West Garrard	14.0	300-399	1195	03-2010
Central	Pineville	West Garrard	89.0	300-399	1195	10-2009
Central	Mill Creek	Hardin County	42.0	300-399	1195	12-2009
Central	Trimble County	Ghent-Speed Line	3.0	300-399	1195	06-2009
Central	J.K. Smith	J.K. Smith CFB	1.0	300-399	1195	06-2012
Central	J.K. Smith	West Garrard	36.0	300-399	1195	12-2009
Central	Maury	Rutherford	27.0	400-599	1732	04-2010
Delta	Cypress	Jacinto	53.0	200-299	884	06-2013
Delta	Porter	Lewis Creek	28.0	200-299	884	06-2018
Delta	Peters Road	Oakville	7.0	200-299	594	09-2012
Delta	Coly	Loblolly	3.0	200-299	705	09-2012
Delta	Sellers Road	Meaux	10.0	200-299	829	06-2011
Delta	Labbe	Sellers Road	15.0	200-299	829	06-2012
Delta	Tillatoba	South Grenada	19.0	200-299	500	06-2014
Delta	Jacinto	Peach Creek	29.0	200-299	884	06-2012
Delta	Peach Creek	Caney Creek	29.0	200-299	884	06-2012
Delta	Caney Creek	Lewis Creek	29.0	200-299	884	06-2012
Delta	Loblolly	Hammond	23.0	200-299	779	06-2013
Gateway	Baldwin Power Plant SS	Prairie State Power Plant	2.0	300-399	1297	06-2010
Gateway	Baldwin Power Plant SS	Prairie State Power Plant	8.0	300-399	1297	06-2010
Gateway	Baldwin Power Plant SS	Rush Island Plant Substation	26.0	300-399	1793	06-2010
Gateway	Prairie State Power Plant	Stallings Substation	8.0	300-399	1195	06-2010
Gateway	Prairie State Power Plant	W. Mount Vernon Substation	2.0	300-399	1195	06-2010
Southeastern	Prattville CT TS	County Line Road TS	1.0	200-299	1003	12-2010
Southeastern	Gaston	Bessemer	1.0	200-299	502	10-2009
Southeastern	Holt	Tuscaloosa	10.0	200-299	807	05-2018
Southeastern	Tensaw SS	TK Rolling Mill	1.0	200-299	433	03-2009
Southeastern	Tensaw SS	TK EAF	3.0	200-299	866	05-2009
Southeastern	Tensaw SS	TK EAF	3.0	200-299	866	05-2009
Southeastern	Tensaw SS	TK Rolling Mill	1.0	200-299	433	03-2009
Southeastern	Tensaw SS	TK EAF	3.0	200-299	866	05-2009
Southeastern	Calvert SS	Tensaw SS	5.0	200-299	865	01-2009
Southeastern	Bucks SS	Tensaw SS	9.0	200-299	865	07-2009
Southeastern	Plant McDonough CC	Plant McDonough (black)	1.0	200-299	1205	06-2011
Southeastern	Plant McDonough CC	Plant McDonough (white)	1.0	200-299	1205	06-2011
Southeastern	Bowen	Villa Rica Primary	28.0	200-299	866	06-2009
Southeastern	Plant McDonough	Smyrna	6.0	200-299	1205	03-2010
Southeastern	Dum Jon	Thomson Primary	23.0	200-299	602	06-2010
Southeastern	Thomson	Warthen	35.0	400-599	2701	06-2010
Southeastern	Clermont Junction	Dawson Crossing	20.0	200-299	602	08-2013
Southeastern	Cumming	Sharon Springs	7.0	200-299	602	06-2013
Southeastern	Vogtle	Thomson	70.0	400-599	3464	06-2015
Southeastern	Bethabara	East Walton	8.0	200-299	602	06-2014
Southeastern	Bostwick	East Walton	4.0	200-299	602	06-2014
Southeastern	East Lake Road	Ola	4.0	200-299	602	06-2010
Southeastern	East Walton	Jack's Creek	9.0	200-299	602	06-2014
Southeastern	East Walton	Rockville	40.0	400-599	3464	06-2014
Southeastern	Jack's Creek	Cornish Mountain	15.0	200-299	602	06-2014
Southeastern	Jim Moore Road	Sharon Church	11.0	200-299	602	06-2010

	Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
	McGrau Ford	Hopewell	12.0	200-299	602	05-2013
	Shoal Creek	Suwanee	8.0	200-299	602	06-2012
	Thomson	Warthen	35.0	400-599	3464	06-2010
	Woodlore	Battlefield	3.0	200-299	866	06-2009
	McConnell Road	Woodlore	5.0	200-299	866	06-2009
	Frey Road	Huntsville	5.0	200-299	866	12-2009
	East Lake Road	Jackson Creek	9.0	200-299	602	06-2010
	Battlefield	Frey Road	3.0	200-299	866	12-2009
	Bethabara	Clarksboro	15.0	200-299	602	03-2010
	Kiln	Carriere SW	26.0	200-299	602	06-2011
VACAR	Pleasant Garden	Asheboro	20.0	200-299	0	06-2011
	Thelma	Carolina	10.0	200-299	1047	06-2011
	Yorktown	Hayes	8.3	200-299	1047	06-2012
	Sowego	Gainesville	14.0	200-299	1047	06-2012
	North Anna	Ladysmith	15.0	400-599	3500	09-2018
	Meadowbrook	Loudoun	65.0	400-599	3500	06-2011
	Iron Bridge	Walmsley	3.0	200-299	706	06-2011
	Walmsley	Southwest	7.0	200-299	706	06-2011
	Loudoun	Middleburg	13.0	200-299	1047	06-2013
	Possum Point	Calvert Cliffs	0.1	400-599	3500	06-2013
	Remington	Sowego	11.0	200-299	1047	06-2012
	Dickerson	Pleasant View	10.5	200-299	1300	06-2011
	Gallows	Ox	13.0	200-299	1047	06-2010
	Hamilton	Middleburg	17.0	200-299	100	06-2013
	Arlington	Ballston	5.0	200-299	1047	06-2013
	Bristers	Garrisonville	13.0	200-299	1047	06-2011
	Carson	Suffolk	50.0	400-599	3450	06-2011
	Chickahominy	Lanexa	14.0	200-299	722	11-2011
	Chickahominy	Old Church	16.0	200-299	797	11-2010
	Clarendon	Rosslyn	1.0	200-299	600	04-2009
	Harrisonburg	Valley	11.0	200-299	797	05-2010
	Hamilton	Pleasant View	12.0	200-299	800	05-2010
	Suffolk	Thrasher	26.0	200-299	1047	06-2011
	Clark	Idylwood	4.0	200-299	515	05-2016
	Landstown	Virginia Beach	11.0	200-299	800	05-2015
	Bristers	Possum Point	35.0	400-599	3464	05-2016
	Reeves Avenue	Sewells Point	11.0	200-299	1047	05-2015
	Chesterfield	Midlothian	22.0	200-299	1047	05-2016
	Elizabeth City	Shawboro	10.0	200-299	1047	06-2012
	Bristers	Gainesville	15.0	200-299	1047	05-2009
	Asheville	Enka	5.0	200-299	566	12-2010
	Richmond	Ft. Bragg Woodruff St	65.0	200-299	1195	06-2011
	Clinton	Lee	26.0	200-299	615	06-2011
	Greenville	Kinston DuPont	30.0	200-299	615	06-2014
	Rockingham	West End	38.0	200-299	1195	06-2011
	Asheboro	Pleasant Garden	22.0	200-299	1195	06-2011
	Harris	RTP	22.0	200-299	1195	06-2012
	Rockingham	Wadesboro Bowman School	12.0	200-299	1256	06-2009
	A M Williams	Cainhoy	11.0	200-299	352	05-2010
	Denny Terrace	Pineland	8.0	200-299	950	12-2010

Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
SPP					
Hugo Switchyard	PSO Valliant Substation	19.0	300-399	913	04-2012
Hugo Switchyard	OG&E Sunnyside Substation	50.0	300-399	913	04-2012
Reno County	Summit	53.4	300-399	1383	07-2010
Rose Hill	Sooner	100.0	300-399	1611	12-2011
Seven Rivers	Pecos Intg	21.0	200-299	452	06-2009
Pecos Intg	Potash Jct	15.0	200-299	452	06-2009
Hitchland	Moore County	50.0	200-299	452	12-2010
Hitchland	Ochiltree Intg.	32.0	200-299	452	06-2011
Mustang	Seminole	18.0	200-299	452	06-2009
Seminole	Hobbs Plt	43.0	200-299	452	06-2010
Northwest sub--OKC	Woodward EHV-Woodward	125.0	300-399	1200	03-2010
Sooner PP Okla	Rose Hill sub-Kansas	50.0	300-399	1200	06-2016
Sunnyside sub	Hugo PP	60.0	300-399	1200	04-2012
BONIN 6	LABBE 6	1.0	200-299	TBD	TBD
Richard	Sellers Rd	32.0	200-299	829	01-2012
Sellers Rd	Segura	19.0	200-299	829	01-2012
Wells	Labbe	30.0	200-299	829	01-2013
Flint Creek	Shipe Road	21.0	300-399	1336	06-2014
Turk	NW Texarkana	34.0	300-399	1336	06-2011
Shipe Road	E. Rogers	9.0	300-399	1336	06-2016
E. Rogers	Osage	32.0	300-399	1336	06-2016
WECC					
AZ-NM-SNV					
Phoenix AZ	Border City NV	0.0	400-599	1905	05-2009
Coronado AZ	Silverking	0.0	400-599	1494	05-2009
El Centro El Centro CA		9.0	200-299	550	12-2009
Phoenix AZ	Phoenix AZ	4.0	200-299	1200	06-2010
Phoenix AZ	Phoenix AZ	12.0	200-299	1200	06-2010
Table Mesa AZ	Phoenix AZ	26.0	400-599	1000	06-2010
Table Mesa AZ	Table Mesa AZ	1.0	400-599	2728	06-2010
San Felipe CA	Bannister CA	23.0	200-299	600	12-2010
Imperial Valley CA	San Felipe CA	38.0	400-599	1200	12-2010
San Felipe CA	Narrows CA	13.0	400-599	1200	12-2010
Stirling Mountain NV	Northwest NV	41.0	200-299	320	01-2011
Coolidge, AZ	Mesa, AZ	57.0	400-599	1405	05-2011
Las Vegas NV	Las Vegas NV	1.0	400-599	3585	06-2011
Coolidge, AZ	Florence, AZ	30.0	200-299	875	06-2011
Florence, AZ	Queen Creek, AZ	13.0	200-299	875	06-2011
Queen Creek AZ	Florence AZ	12.0	200-299	875	06-2011
Eleven Mile Corner, AZ	Red Rock, AZ	30.0	400-599	1100	06-2011
Las Vegas NV	Mercury NV	75.0	200-299	1200	06-2012
Gilbert AZ	Queen Creek AZ	20.0	200-299	875	06-2012
Queen Creek AZ	Florence AZ	20.0	200-299	875	06-2012
Vista NV	Pahrump NV	11.0	200-299	320	12-2012
Casa Grande, AZ	Coolidge AZ	21.0	200-299	833	05-2013
Maricopa AZ	Coolidge, AZ	30.0	400-599	1405	05-2013
Phoenix AZ	Phoenix AZ	15.0	200-299	1200	06-2013
Phoenix AZ	Phoenix AZ	15.0	200-299	1200	06-2013
Las Vegas NV	Las Vegas NV	1.0	200-299	1200	06-2013

Terminal From Location		Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
	Las Vegas NV	Las Vegas NV	1.0	200-299	1200	06-2013
	Las Vegas NV	Las Vegas NV	18.0	200-299	810	06-2013
	Las Vegas NV	Las Vegas NV	18.0	200-299	810	06-2013
	Las Vegas NV	Las Vegas NV	4.0	200-299	810	06-2013
	Las Vegas NV	Las Vegas NV	8.0	400-599	3000	06-2013
	Las Vegas NV	Las Vegas NV	8.0	400-599	3000	06-2013
	Las Vegas NV	Las Vegas NV	28.0	400-599	3000	06-2013
	Mobile AZ	Maricopa AZ	13.0	400-599	1500	06-2013
	Ancho, NM	Coolidge AZ	460.0	400-599	3000	01-2014
	Four Corners NM	Red Mesa AZ	189.0	400-599	1300	04-2014
	West Phoenix AZ	West Phoenix AZ	15.0	200-299	1200	06-2014
	Peoria AZ	Pioneer AZ	9.0	200-299	1200	06-2014
	Palo Verde AZ	Phoenix AZ	45.0	400-599	600	06-2014
	Wintersburg AZ	Yuma AZ	115.0	400-599	1200	06-2014
	Moenkopi AZ	Marketplace NV	218.0	400-599	1300	06-2014
	Las Vegas NV	Boulder City NV	61.0	400-599	3000	06-2014
	Cochise, AZ	Benson, AZ	16.0	200-299	TBD	06-2014
	Red Rock AZ	Vail AZ	60.0	300-399	925	06-2014
	Red Mesa AZ	Moenkopi AZ	62.0	400-599	1300	12-2014
	Sahuarita AZ	Nogales AZ	60.0	300-399	925	12-2014
	Sahuarita AZ	Nogales AZ	60.0	300-399	925	12-2014
	West Phoenix AZ	West Phoenix AZ	12.0	200-299	1200	06-2015
	West Phoenix AZ	West Phoenix AZ	12.0	200-299	1200	06-2015
	Las Vegas NV	Las Vegas NV	16.0	200-299	810	06-2015
	Las Vegas NV	Las Vegas NV	1.0	200-299	810	06-2015
	Las Vegas NV	Las Vegas NV	16.0	200-299	810	06-2015
	Las Vegas NV	Las Vegas NV	1.0	200-299	810	06-2015
	Las Vegas NV	Las Vegas NV	16.0	200-299	810	06-2015
	Las Vegas NV	Las Vegas NV	15.0	200-299	810	06-2015
	Benson, AZ	Sahuarita, AZ	68.7	200-299	TBD	06-2015
	Northwest of Phoenix AZ	Peoria AZ	40.0	400-599	1200	06-2016
	Boulder City NV	Mercury NV	110.0	400-599	3000	06-2016
	Las Vegas NV	Mercury NV	75.0	400-599	3000	06-2016
	Winchester AZ	Vail AZ	40.0	300-399	581	12-2017
	Vail AZ	Sahuarita AZ	14.0	300-399	925	12-2017
	Springerville AZ	Greenlee AZ	110.0	300-399	925	12-2017
	Maricopa As	Sahuarita AZ	178.0	300-399	925	12-2017
	Red Rock AZ	Sahuarta AZ	68.0	300-399	425	12-2017
	Red Rock AZ	Winchester AZ	80.0	400-599	1000	12-2017
	Phoenix AZ	Phoenix AZ	7.0	200-299	1200	06-2018
	Las Vegas NV	Las Vegas NV	5.0	200-299	810	06-2018
	Sierra Vista, AZ	Sierra Vista, AZ	2.0	200-299	TBD	06-2018
	Pima County, AZ	Sierra Vista, AZ	36.0	200-299	TBD	06-2018
	Pima County, AZ	Sierra Vista, AZ	8.0	200-299	TBD	06-2018
CA-MX US	Rancho Vista CA	Pauda CA	15.0	200-299	2480 AMP	06-2009
	Rancho Vista CA	Mira Loma CA	7.0	200-299	2480 AMP	06-2009
	Rancho Vista CA	Etiwanda CA	1.0	200-299	3230 AMP	06-2009
	Rancho Vista CA	Etiwanda CA	1.0	200-299	3230 AMP	06-2009
	Rancho Vista CA	Serrano CA	30.0	400-599	3950 AMP	06-2009
	Encina	Penasquitos	11.0	200-299	600	06-2009

Region	Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
	Contra Costa Substation	Las Positas Substation	28.0	200-299	683	02-2010
	Newark Substation	Ravenswood Substation	18.0	200-299	1366	05-2010
	Birds Landing	Contra Costa Substation	18.0	200-299	754	05-2010
	Table Mountain Substation	Rio Oso Substation	136.0	200-299	604	05-2010
	Tehachapi CA	Saugus CA	82.7	400-599	3950 AMP	06-2010
	Julian Hinds CA	Buck Blvd CA	66.0	200-299	3950 AMP	06-2010
	Intermountain UT	Adelanto CA	0.0	400-599	2400	11-2010
	Pittsburg Substation	Telsa Substation	62.0	200-299	683	12-2010
	Telsa Substation	Newark Substation	54.0	200-299	1366	05-2011
	Vaca Dixon Substation	Birds Landing SS	50.0	200-299	754	05-2011
	Lakeville Substation	Lakeville Substation	0.5	200-299	658	05-2011
	Contra Costa Substation	Moraga Substation	54.0	200-299	683	05-2011
	Devers CA	Mirage CA	15.0	200-299	1240 AMP	06-2011
	O'Banion CA	Elverta CA	26.0	200-299	1200	04-2012
	San Diego CA	San Diego CA	40.0	200-299	600	06-2012
	San Diego CA	San Diego CA	40.0	200-299	600	06-2012
	Imperial Valley CA	San Diego CA	100.0	400-599	600	06-2012
	Barren Ridge CA	Castaic CA	72.0	200-299	800	08-2013
	Rector CA	Springville CA	38.0	200-299	3230 AMP	12-2012
	Vaca Dixon Substation	Lakeville Substation	80.0	200-299	658	05-2013
	Tehachapi CA	Mira Loma CA	250.0	400-599	3950 Amp	06-2013
	Barren Ridge CA	Haskell CA	61.0	200-299	800	08-2013
	Devers II CA	Hesperia CA	85.0	400-599	600	11-2013
	Devers II CA	Devers CA	2.0	400-599	1200	11-2013
	Harquahala Junction AZ	Devers CA	270.0	400-599	2700 AMP	12-2013
	Bakersfield, Ca	Fresno, Ca	280.0	400-599	2146	12-2013
	Selkirk BC	Collinsville CA	2500.0	400-599	3000	12-2015
	Collinsvills, CA	Pittsburg, CA	8.0	400-599	800 and 2146	12-2015
	Magunden CA	Rector CA	160.0	200-299	3950 AMP	06-2017
NWPP	Covington WA	Berrydale WA	10.0	200-299	480	05-2009
	Bluffdale UT	SLC UT	0.0	300-399	600	06-2009
	Beaver	Allston	0.0	200-299	TBD	06-2009
	Beaver	Port Westward	0.5	200-299	TBD	06-2009
	Port Westward	Trojan	19.0	200-299	TBD	06-2009
	Olympia WA	Shelton WA	14.0	200-299	697	11-2009
	Olympia WA	Shelton WA	34.0	200-299	697	11-2009
	St. George, UT	St. George, UT	20.0	300-399	600	05-2010
	Bluffdale UT	SLC UT	0.0	300-399	600	05-2010
	Midpoint, ID	King, ID	24.0	200-299	339	06-2010
	King, ID	DRAM, ID	80.0	200-299	339	06-2010
	Midpoint, ID	DRAM, ID	-104.0	200-299	339	06-2010
	Cedar City UT	Cedar City UT	1.0	300-399	1163	06-2010
	Cedar City UT	Cedar City UT	1.0	300-399	1163	06-2010
	Walla Walla, WA	McNary, OR	0.0	200-299	600	06-2010
	Downey, ID	SLC UT	135.0	300-399	600	06-2010
	Great Falls	U. S Border	135.0	200-299	534	06-2010
	Casper, WY	Dave Johnston SS, WY	0.0	200-299	600	09-2010
	Bluffdale UT	SLC UT	10.0	300-399	1396	06-2011
	Reno NV	Dayton NV	17.0	300-399	600	06-2012
	Carson Lake, NV	Fallon, NV	20.0	200-299	200	06-2012

	Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
	Ely NV	Las Vegas NV	250.0	400-599	3000	06-2012
	Ely NV	Boulder City NV	230.0	400-599	3000	06-2012
	Umatilla, OR	Rufus, OR	79.0	400-599	4936	12-2012
	Douglas Switchyard	Rapids Switchyard	15.0	200-299	1000	12-2012
	Townsend MT	Midpoint, ID	460.0	400-599	1500	01-2013
	Walters Ferry, ID	Kuna, ID	30.0	200-299	550	06-2013
	Walters Ferry, ID	Nampa, ID	22.0	200-299	550	06-2013
	Shoshone, ID	Walters Ferry, ID	126.0	400-599	3000	06-2013
	Walters Ferry, ID	Burns, OR	134.0	400-599	3000	06-2013
	Shoshone, ID	Burns, OR	-260.0	400-599	3000	06-2013
	Walters Ferry, ID	Boardman, OR	300.0	400-599	3000	06-2013
	Clyde, WA	Central Ferry, WA	40.0	400-599	TBD	12-2013
	The Dalles, OR	Goldendale, WA	28.0	400-599	TBD	12-2013
	Rock Springs, WY	Downey, ID	189.0	400-599	3000	06-2014
	Rock Springs, WY	Downey, ID	189.0	400-599	3000	06-2014
	Gresham OR	Troutdale OR	9.0	200-299	418	06-2014
	Reno NV	Doyle CA	50.0	300-399	600	06-2014
	Twin Falls ID	Ely NV	280.0	400-599	3000	06-2014
	Medicine Bow UT	Various	2200.0	400-599	TBD	06-2014
	Dayton NV	Reno NV	15.0	300-399	600	08-2014
	American Falls, ID	Pocatello, ID	32.0	300-399	1386	06-2015
	Shoshone, ID	Pocatello, ID	-84.0	300-399	2079	06-2015
	Shoshone, ID	Pocatello, ID	-32.0	300-399	1386	06-2015
	Downey, ID	Hollister, ID	115.0	400-599	3000	06-2015
	Hollister, ID	Walters Ferry, ID	153.0	400-599	3000	06-2015
	Downey, ID	American Falls, ID	51.0	400-599	3000	06-2015
	Shoshone, ID	American Falls, ID	84.0	400-599	3000	06-2015
	Hollister, ID	Shoshone, ID	34.0	400-599	3000	06-2015
	Shoshone, ID	Walters Ferry, ID	126.0	400-599	3000	06-2015
	Sherwood Substation	Sherwood OR	5.0	200-299	597	11-2015
	Castle Rock, WA	Troutdale or Wilsonville, OR	75.0	400-599	TBD	12-2015
	Eagle ID	Boise ID	14.0	200-299	550	05-2017
	Brownlee ID	Boise ID	-100.0	200-299	394	05-2017
	Brownlee ID	Eagle ID	78.0	200-299	394	05-2017
	Eagle ID	Boise ID	22.0	200-299	394	05-2017
	Carson City, NV	Las Vegas NV	265.0	400-599	3000	06-2018
RMPA	Donkey Creek WY	Pumpkin Buttes WY	75.0	200-299	460	04-2009
	Dry Fork	Hughes	17.0	200-299	460	05-2009
	Dry Fork	Carr Draw	23.0	200-299	460	05-2009
	Dry Fork	Arvada	50.0	200-299	460	08-2009
	Arvada	Tongue River	40.0	200-299	460	08-2009
	Tongue River	Sheridan WY	11.0	200-299	460	08-2009
	Hughes WY	Sheridan WY	105.0	200-299	460	12-2009
	Cheyenne WY	Ault CO	35.0	200-299	402	12-2009
	Chambers CO	Spruce CO	8.0	200-299	500	05-2010
	Chambers CO	Tower CO	8.0	200-299	500	05-2010
	Spruce CO	Tower CO	-8.0	200-299	500	05-2010
	Comanche CO	Fuller CO	-78.0	200-299	506	05-2010
	Midway CO	Daniels Park #2 CO	-75.0	200-299	800	05-2010
	Comanche CO	Midway CO	50.0	200-299	506	05-2010

	Terminal From Location	Terminal To Location	Line Length (Circuit Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected In-Service Date
	Midway CO	Fuller CO	30.0	200-299	800	05-2010
	Comanche CO	Daniels Park #1 CO	125.0	300-399	1200	05-2010
	Comanche CO	Daniels Park #2 CO	125.0	300-399	1200	05-2010
	Erie, CO	Hoyt, CO	45.3	200-299	TBD	10-2010
	Midway CO	Waterton CO	82.0	300-399	1200	05-2011
	Longmont CO	Platteville CO	21.0	200-299	398	01-2011
	Fort Collins CO	Loveland CO	10.0	200-299	472	05-2011
	Alcova, WY	Miracle Mile (West), WY	24.1	200-299	TBD	10-2011
	Walsenburg CO	San Luis Valley CO	80.0	200-299	613	12-2013
	Alcova, WY	Casper (South), WY	28.6	200-299	TBD	10-2012
	Boyd (Larimer), CO	Weld county, Co	12.7	200-299	TBD	10-2012
	Pawnee CO	Smoky Hill CO	96.0	300-399	735	05-2013
	Casper (South) WY	Dave Johnston SS, WY	31.3	200-299	TBD	10-2013
	Alcova, WY	Miracle Mile (East), WY	24.1	200-299	TBD	10-2014
	Alcova, WY	Casper (North), WY	28.6	200-299	TBD	10-2015
	Casper (North), WY	Dave Johnston SS, WY	37.5	200-299	TBD	10-2016
	Lovell, WY	Yellowtail, MT	46.8	200-299	TBD	12-2017
WECC CA	Ingledow, BC	Custer, WA	14.0	400-599	300 Amp	03-2010
WECC CA	Brintnell AB	Wesley Creek AB	145.0	200-299	550/702	04-2010
WECC CA	Peigan AB	North Lethbridge AB	37.0	200-299	600/744	06-2010
WECC CA	Peigan AB	Goose Lake AB	20.0	200-299	600/744	06-2010
WECC CA	Genesee AB	Ellerslie AB	20.0	400-599	2600	06-2010
WECC CA	North Lethbridge AB	Canada - US Border	80.0	200-299	534	06-2010
WECC CA	V. Lake Terminal BC	R.G. Anderson BC	17.0	200-299	506	12-2010
WECC CA	V. Lake Terminal BC	R.G. Anderson BC	17.0	200-299	506	12-2010
WECC CA	V. Lake Terminal BC	Bentley BC	7.0	200-299	506	12-2010
WECC CA	Genesee AB	Langdon AB	206.0	400-599	3000	11-2011
WECC CA	Genesee AB	Keephills AB	20.0	400-599	2600	12-2012
WECC CA	Nicola BC	Meridian BC	153.0	400-599	3000 Amp	10-2014
CA-MX Mex	La Jovita MX	Presidente Juarz MX	38.0	200-299	430	10-2009
CA-MX Mex	La Jovita MX	El Ciprés MX	38.0	200-299	430	10-2009
CA-MX Mex	La Jovita MX	Lomas MX	38.0	200-299	430	10-2009
CA-MX Mex	Mexicali MX	Tecnologico MX	10.0	200-299	388	10-2010
CA-MX Mex	El Centenario MX	La Rosita MX	10.0	200-299	388	06-2010
CA-MX Mex	El Centenario MX	Sanchez Taboada MX	10.0	200-299	388	06-2010
CA-MX Mex	Ejido Michoacan de Ocampo	Mexicali MX	30.0	200-299	388	06-2012
CA-MX Mex	Ejido Michoacan de Ocampo	Tecnologico MX	30.0	200-299	388	10-2012
CA-MX Mex	Ejido Michoacan de Ocampo	Sanchez Taboada MX	30.0	200-299	388	10-2012
CA-MX Mex	La Jovita MX	La Herradura MX	50.0	200-299	430	10-2013
CA-MX Mex	El Cañon MX	El Ciprés MX	52.0	200-299	430	10-2015

Projected Transformers - Low-side > 200 kV

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
MRO				
Lyon County	345	115	Apr-13	
Franklin	345	115	Apr-13	
Hazel #1	345	230	Apr-13	
Hazel #2	345	230	Apr-13	
Rush City	230	69	Dec-11	
Effie	230	69	Dec-11	
Grand Island 345/230 T-3	345	230	Jun-09	Under Construction
Bison 345/230 kV Transformer #1	345	230	Dec-15	In conjuction with Fargo - St. Cloud 345 kV line (CapX), a new 345/230 kV tf near Fargo, ND
Bison 345/230 kV Transformer #2	345	230	Dec-15	In conjuction with Fargo - St. Cloud 345 kV line (CapX), a new 345/230 kV tf near Fargo, ND
CAPX Group 1	345	230	Jul-05	Install two, 345/230 kV tfs at Hazel Creek Substation as part of the CAPX group 1 projects
CAPX Group 1	345	230	Jul-05	Install two, 345/230 kV tfs at Hazel Creek Substation as part of the CAPX group 1 projects
Riel	500	230	May-14	Associated with Bipole 3 / Conawapa project
Rhame	230	115	Sep-09	
Williston	230	115	Dec-10	
NPCC				
Greater Boston Reliability Project	345	230	Dec-12	Waltham Substation - install one autotransformer.
Chénier	735	315	Sep-11	One 1650 MVA transformer
Bout-de-l'Île	735	315	Nov-13	Two 1650 MVA transformers
Montagnais	735	315	Sep-16	Two 600 MVA transformers
Oshawa Area TS	500	230	Jul-05	Conceptual
Milton TS	500	230	Jul-05	Conceptual
RFC				
Tallmadge	345	138	Dec-08	In-Service
Metuchen	230	138	Jan-09	In-Service
Hiple	345	138	May-09	Under Construction
Cumberland	230	138	May-09	Under Construction
Red Lion	230	138	May-09	Under Construction
Murphy	345	138	Jun-09	Under Construction
Roseland	500	138	Jun-09	Under Construction
Brighton	500	230	Jun-09	Under Construction
Don Marquis	345	138	Jun-09	Under Construction
Beddington	500	230	Jun-09	Under Construction
Tangy	345	138	Jun-09	Under Construction
Avon	345	138	Jun-09	Under Construction

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
SERC				
J.K. Smith #2	345	230	Jun-09	Install 2nd J.K. Smith 345/138 kV autotransformer. Low-side voltage is 138 kV.
O'Hara 500/230 kV transformer #2 addition	500	230	Jun-16	Add a 2nd 2000 MVA 500/230 kV transformer @ O'Hara
Thomson	500	230	Jun-10	New 1344 MVA 500/230 kV transformer @ Thomson; Under construction
Middle Fork 500/230 kV project	500	230	Jun-17	New 2016 MVA 500/230 kV addition @ Middle Fork
East Walton	500	230	Jun-14	Add 2016 MVA transformer
Suffolk 2	500	230	Jun-11	b0329
Dooms	500	230	Jun-09	b0339
Bristers	500	230	May-09	b0227
Suffolk 1	500	230	Jun-09	b0231.2
Wake 500 kV Sub, Add 3rd 500/230 kV Transformer Ba	500	230	Jun-14	Currently in the planning phase of project life. In-service date is dependent on load and changes in generation or interchange
SPP				
Hitchland Project	345	230	Apr-10	Project in final design - transformer on order
Knoll	345	230	Dec-12	Economic upgrade dependent upon new construction of Spearville - Knoll - Axtell via the balanced portfolio
Acadiana Load Pocket Project	500	230	Jan-13	Wells 500-230 kV Transformer
WECC				
BCHA, Selkirk Transformer Addition	500	230	Mar-10	Add transformer T4 Delayed
PAC, Camp Williams SVC	345	N/A	Jun-09	N/A
SPP, Robinson 345/500kV Transformer	500	345	Jun-12	N/A
SPP, Robinson 345/500kV Transformer #2	500	345	Jun-12	N/A
IPC, Gateway West Transm.	500	345	Jun-15	N/A
TSGT, Energy Center 500/230 kV Transformer #1	500	230	Dec-12	Tentative Eastern Plains Transmission Project Component to deliver 1400 MW of generation in Holcomb KS to Colorado
TSGT, Energy Center 500/230 kV Transformer #2	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Burlington 500/230 kV Transformer #1	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Burlington 500/230 kV Transformer #2	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Big Sandy 500/230 kV Transformer #2	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Boone 500/230 kV Transformer #1	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Boone 500/230 kV Transformer #2	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
TSGT, Midway 500/230 kV Transformer #1	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Midway 500/230 kV Transformer #2	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
TSGT, Big Sandy 500/230 kV Transformer #1	500	230	Dec-12	Tentative Eastern Plains Trans. Project Component (see above)
SRP, Springerville #4	500	345	Mar-10	N/A
NEVP, Northwest 500/230 kV Transformer	500	230	Jun-11	N/A
SRP, Southeast Valley Project	500	N/A	Jun-11	N/A
SWTC, Bicknell 345/230 kV Transformer	345	230	Jun-12	Transformer replacement
SWTC, Greenlee 345/230 kV Transformer	345	230	Jun-12	2nd Transformer
NEVP, Harry Allen 345/230 kV Transformer	345	230	May-13	N/A
NEVP, Sunrise 500/230 kV Transformer	500	230	Jun-13	N/A
NEVP, Amaragosa 500/230kV Transformer	500	230	Jun-16	N/A
NEVP, Thunderbird 500/230 kV Transformer	500	230	Jun-18	N/A
SCE, Rancho Vista Substation	500	230	Jun-09	500/230 kV transformer bank. Under Const. Under Const.
SCE, Rancho Vista Substation	500	230	Jun-09	500/230 kV transformer bank. Under Const. Under Const.
SCE, Lugo Bank 3AA	500	230	Jun-10	N/A
SDGE, Sunrise Powerlink	500	230	Jun-11	New substation, 500/230kV 500/230/12 kV xfmr banks Delayed 1 yr due to state reg. process Delayed 1 yr due to state reg. process
SDGE, Sunrise Powerlink	500	230	Jun-11	New substation, 500/230kV 500/230/12 kV xfmr banks Delayed 1 yr due to state reg. process Delayed 1 yr due to state reg. process

Terms Used in this Report

Ancillary (Controllable Demand Response) — Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Capacity (Controllable Demand Response**) —** Demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Categories — *See* ***Existing Generation Resources, Future Generation Resources,*** *and* ***Conceptual Generation Resources***.

Capacity Margin (%) — *See* ***Deliverable Capacity Margin (%)*** *and* ***Prospective Capacity Margin (%)***. Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with *Reserve Margin(s) (%)* for NERC Assessments.

Conceptual Generation Resources — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

1. Corporate announcement
2. Entered into or is in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Conservation – *see* ***Energy Conservation***

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. 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.

Controllable (Demand Response**)** — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** 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.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, 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.

Curtailable — *See* ***Contractually Interruptible***

Deliverable Capacity Margin (%) — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Deliverable Capacity Resources. Replaced in 2009 with *Deliverable Capacity Reserve Margin (%)* for NERC Assessments.

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

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

Demand – *See* ***Net Internal Demand***, ***Total Internal Demand***

Demand Bidding & Buyback (Controllable Energy-Price Demand Response**) —** 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.

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.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — Demand-Side Management that is under the direct 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.[289]

Dispatchable (Demand Response**)** — Demand-side resource curtails according to instruction from a control center.

Disturbance Classification Scale — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Disturbance Event – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Economic (Controllable Demand Response**) —** Demand-side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) **—** Demand-side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

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.

[289] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 www.nerc.com/files/Glossary_2009April20.pdf

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP—002-0:

- **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.

Energy Only (Capacity) — 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.

Energy-Price (Controllable Economic Demand Response**) —** Demand-side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

Existing, Certain (Existing Generation Resources) — 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:

1. Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[290] that is eligible to bid into a market or has been designated as a firm network resource.

[290] 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.

3. Network Resource[291], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
4. Energy-only resources[292] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[293]
5. Capacity resources that can not be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[294] during the period of analysis in the assessment.

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

Existing, Certain and Net Firm Transactions (%) (Margin Category) – Existing, Certain & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources — *See Existing, Certain, Existing, Other, Existing, but Inoperable.*

Existing, Inoperable (Existing Generation Resources) — 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 Existing, Certain or Existing, Other, but is not limited to, the following:

1. Mothballed generation (that can not be returned to service for the period of the assessment).
2. Other existing but out-of-service generation (that can not be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecasted to return to service.

Existing, Other (Existing Generation Resources) — 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 Existing, Certain. This category includes, but is not limited to the following:

1. A resource with non-firm or other similar transmission arrangements.
2. 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.
3. Mothballed generation (that may be returned to service for the period of the assessment).

[291] 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.

[292] 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.

[293] Energy only resources with transmission service constraints are to be considered in category Existing, Other.

[294] Energy only resources with transmission service constraints are to be considered in category Existing, Other.

4. Portions of variable generation not counted in the Existing, Certain category (e.g., wind, solar, etc. that may not be available or derated during the assessment period).
5. Hydro generation not counted as Existing, Certain or derated.
6. Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

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.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

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.

Future Generation Resources (*See also* ***Future, Planned*** *and* ***Future, Other***) — 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:

1. Construction has started.
2. Regulatory permits being approved, any one of the following:
   a. Site permit
   b. Construction permit
   c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future, Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future, Planned* 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:

1. Be curtailed or interrupted at any time for any reason.
2. Energy-only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the *Future, Planned* category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in category *Future, Planned* or derated.
5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future, Planned (Future Generation Resources) — 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:

1. Contracted (or firm) or other similar resource.

2. Where organized markets exist, designated market resource[295] that is eligible to bid into a market or has been designated as a firm network resource.
3. Network Resource[296], as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[297]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

Load as a Capacity Resource (Controllable Capacity Demand Response) — Demand-side resources that commit to pre-specified load reductions when system contingencies arise.[298]

NERC's Bulk Power System Disturbance Classification Scale[299] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staff to determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's Bulk Power System Event Classification Scale is designed to classify bulk power system disturbances by severity, size, and impact to the general public.

<u>Operating Security Events</u> — Operating reliability events are those that significantly affect the integrity of interconnected system operations. They are divided into 5 categories to take into account their different system impact.

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. "Clear-Sky" Inter-area oscillations.
f. Intended and controlled system separation by proper Special Protection Schemes / Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.

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

a. Complete loss of dc converter station.

---

[295] 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.

[296] 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.

[297] Energy only resources with transmission service constraints are to be considered in category Future, Other.

[298] 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.

[299] http://www.nerc.com/page.php?cid=5%7C252

b. The loss of multiple bulk power transmission components.
c. The loss of an entire switching station (all lines, 100 kV or above).
d. The loss of an entire generation station of 5 or more generators (aggregate stations of 75 MW or higher).
e. Loss of off-site power (LOOP) to a nuclear generating station.
f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.
h. 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 Texas or Québec Interconnections).
i. The planned automatic rejection of generation through special protection schemes (SPS) or remedial action schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.
k. SPS/RAS misoperation.

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

a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.

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

a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.

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

a. The loss of load of 10,000 MW or more.
b. The loss of generation of 10,000 MW or more.

Resource Adequacy Events — Adequacy events are divided into three categories based on Standard EOP—002-0 (Capacity and Energy Emergencies).

Category A1: No disturbance events and all available resources in use.

a. Required Operating Reserves can not be sustained.
b. Non-firm wholesale energy sales have been curtailed.

Category A2: Load management procedures in effect.

1. Public appeals to reduce demand.
2. Voltage reduction.
3. Interruption of non-firm end per contracts.
4. Demand-side management.
5. Utility load conservation measures.

Category A3: Firm load interruption imminent or in progress.

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.

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.

Non-dispatchable (Demand Response**) —** Demand-side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

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.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity**) —** The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories – *See **NERC's Bulk Power System Disturbance Classification Scale***

Prospective Capacity Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Prospective Capacity Resources. Replaced in 2009 with *Prospective Capacity Reserve Margin (%)* for NERC Assessments.

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

Prospective Capacity Resources – 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. (MW)

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

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.

Purchases/Imports Contracts – *See **Transaction Categories***

Real Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** 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.

Reference Reserve Margin Level – *See **NERC Reference Reserve Margin Level***

Regulation (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes can not be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[300] The government of Canada has a similar definition.[301] Variable generation is a subset of Renewable Energy—See ***Variable Generation***.

Renewables — *See* ***Renewable Energy***

Reserve Margin (%) — *See* ***Deliverable Capacity Reserve Margin (%)*** *and* ***Prospective Capacity Reserve Margin (%)***. Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Resource Adequacy Events — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Sales/Exports Contracts – *See* ***Transaction Categories***

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — 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.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response**) -** Rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

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.

Total Internal Demand: The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. 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 indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, 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). Adjustments for controllable demand response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response**) —** Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus

[300] http://www1.eere.energy.gov/site_administration/ glossary.html#R
[301] http://www.cleanenergy.gc.ca/faq/ index_e.asp#whatiscleanenergy

provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods.

Transaction Categories (*See also* ***Firm, Non-Firm, Expected*** *and* ***Provisional)*** **—** 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.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the region.

> Example: If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Loading Relief (TLR) Levels — Various levels of the TLR Procedure from Reliability Standard IRO—006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations
- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priorityTransmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

Transmission Status Categories — Transmission additions were categorized using the following criteria:

- **Under Construction**
  - Construction of the line has begun
- **Planned (any of the following)**
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual (any of the following)**
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as "Under Construction" or "Planned"
  - Projected transmission lines that are not "Under Construction" or "Planned"

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[302] Variable generation sources which include wind, solar, ocean and some hydro generation resources are all renewable based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the bulk power system planning and operations: variability and uncertainty.

- Variability: The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.
- Uncertainty: The magnitude and timing of variable generation output is less predictable than for conventional generation.

References:

Glossary of Terms Used in Reliability Standards, Updated April 20, 2009
www.nerc.com/files/Glossary_2009April20.pdf

Instructions for NERC Long-Term Reliability Assessment – Data Reporting Form ERO-2009LTRA, November 26, 2008

Reliability Assessments Guidebook, Version 1.2, March 18, 2008
http://www.nerc.com/docs/pc/ragtf/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf

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

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

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
EE	Energy Efficiency
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
LOOP	Loss of off-site power
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
SPS/RAS	Special Protection Schemes / Remedial Action Schemes
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
var	Voltampre reactive
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 Assessment Subcommittee Roster

Chair	William O. Bojorquez Vice President, Planning	Hunt Transmission Services, L.L.C. 701 Brazos Street, Suite 970 Austin, Texas 78701–2559	(512) 721–2653 (512) 721–2656 Fx bbojorquez@hunttransmission.com
Vice Chair	Mark J. Kuras Senior Engineer, NERC and Regional Coordination	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403–2497	(610) 666-8924 (610) 666-4779 Fx kuras@pjm.com
ERCOT	Dan Woodfin Director, System Planning	Electric Reliability Council of Texas, Inc. 2705 West Lake Drive Taylor, Texas 76574	(512) 248–3115 (512) 248–4235 Fx dwoodfin@ercot.com
FRCC	Vince Ordax Manager of Planning	Florida Reliability Coordinating Council 1408 N. Westshore Boulevard Suite 1002 Tampa, Florida 33607–4512	(813) 207–7988 (813) 289–5646 Fx vordax@frcc.com
MRO	Hoa Nguyen Resource Planning Coordinator	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, North Dakota 58501	(701) 222–7656 (701) 222–7970 Fx hoa.nguyen@mdu.com
NPCC	John G. Mosier, Jr. AVP-System Operations	Northeast Power Coordinating Council, Inc. 1040 Avenue of the Americas-10th floor New York, New York 10018–3703	(917) 697–8565 Cell (212) 840–4907 (212) 302 –2782 Fx jmosier@npcc.org
RFC	Jeffrey L. Mitchell Director - Engineering	ReliabilityFirst Corporation 320 Springside Drive Suite 300 Akron, Ohio 44333	(330) 247–3043 (330) 456–3648 Fx jeff.mitchell@rfirst.org
RFC	Bernard M. Pasternack, P.E. Managing Director - Transmission Asset Management	American Electric Power 700 Morrison Road Gahanna, Ohio 43230–8250	(614) 552–1600 (614) 552–1602 Fx bmpasternack@aep.com
SERC	Hubert C. Young Manager of Transmission Planning	South Carolina Electric & Gas Co. 220 Operations Way MC J37 Cayce, South Carolina 29033	(803) 217–2030 (803) 933–7264 Fx cyoung@scana.com
SPP	Mak Nagle Manager of Technical Studies & Modeling	Southwest Power Pool 415 North McKinley Suite 140 Little Rock, Arkansas 72205–3020	(501) 614–3564 (501) 666–0346 Fx mnagle@spp.org
WECC	James Leigh-Kendall Manager, Reliability Compliance and Coordination	Sacramento Municipal Utility District Mail Stop B305 P.O. Box 15830 Sacramento, California 95852–1830	(916) 732–5357 (916) 732–7527 Fx jleighk@smud.org

WECC	Bradley M. Nickell Renewable Integration and Planning Director	Western Electricity Coordinating Council 615 Arapeen Drive, Suite 210 Salt Lake City, UT 84108	(801) 455-7946 (720) 635-3817 bnickell@wecc.biz
Canadian-At-Large	Daniel Rochester, P. Eng. Manager, Reliability Standards and Assessments	Independent Electricity System Operator Station A, Box 4474 Toronto, Ontario, M5W 4E5	(905) 855-6363 (416).574.4018 Cell (905) 403-6932 Fx dan.rochester@ieso.ca
IOU & DCWG Chair	K. R. Chakravarthi Manager, Interconnection and Special Studies	Southern Company Services, Inc. 13N-8183 P.O. Box 2641 Birmingham, Alabama 35291	(205) 257–6125 (205) 257–1040 Fx krchakra@southernco.com
LFWG Chair	Yves Nadeau Manager, Load and Revenue Forecasting	Hydro-Québec Complexe Desjardins, Tour Est 25 étage -- Case postale 10000 Montréal, Québec H5B 1H7	(514) 879–4100 ext 6131 nadeau.yves@hydro.qc.ca
ISO/RTO	Jesse Moser Manager-Regulatory Studies	Midwest ISO P.O. Box 4202 Carmel, IN 46082–4202	(612) 718–6117 jmoser@midwestiso.org
ISO/RTO	John Lawhorn, P.E. Director, Regulatory and Economic Standards Transmission Asset Management	Midwest ISO, Inc. 1125 Energy Park Drive St. Paul, Minnesota 55108	(651) 632–8479 (651) 632–8417 Fx jlawhorn@midwestiso.org
ISO/RTO	Peter Wong Manager, Resource Adequacy	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040–2841	(413) 535–4172 (413) 540–4203 Fx pwong@iso-ne.com
FERC	Keith N. Collins Manager, Electric Analysis Group	Federal Energy Regulatory Commission 888 First Street, NE Washington, D.C. 20426	(202) 502-6383 (202) 219-6449 Fx keith.collins@ferc.gov
FERC	Sedina Eric Electrical Engineer, Office of Electric Reliability, Division of Bulk Power System Analysis	Federal Energy Regulatory Commission 888 First Street, NE, 92–77 Washington, D.C. 20426	(202) 502–6441 (202) 219–1274 Fx sedina.eric@ferc.gov
DOE	Patricia Hoffman Acting Director Research and Development	Department of Energy 1000 Independence Avenue SW 6e–069 Washington, D.C. 20045	(202) 586–1411 patricia.hoffman@hq.doe.gov
Alternate SERC	Herbert Schrayshuen Director Reliability Assessment	SERC Reliability Corporation 2815 Coliseum Centre Drive Charlotte, North Carolina 28217	(704) 940–8223 (315) 439–1390 Cell hschrayshuen@serc1.org

Alternate FRCC	John E. Odom, Jr. Vice President of Planning and Operations	Florida Reliability Coordinating Council 1408 N. Westshore Blvd. Suite 1002 Tampa, Florida 33607	(813) 207–7985 (813) 289–5646 Fx jodom@frcc.com
Alternate MRO	John Seidel Reliability Assessment Manager	Midwest Reliability Organization 2774 Cleveland Ave Roseville, Minnesota 55113	(651) 855–1716 (651) 855–1712 Fx ja.seidel@midwestreliability.org
Alternate MRO	Salva R. Andiappan Principal Engineer	Midwest Reliability Organization 2774 Cleveland Ave Roseville, Minnesota 55113	(651) 855–1719 (651) 855–1712 Fx sr.andiappan@midwestreliability.org
Alternate RFC	Paul D. Kure Senior Consultant, Resources	Reliability*First* Corporation 320 Springside Drive Suite 300 Akron, Ohio 44333	(330) 247–3057 (330) 456–3648 Fx paul.kure@rfirst.org
Alternate SPP	Alan C. Wahlstrom Lead Engineer, Compliance	Southwest Power Pool 16101 La Grande Drive Suite 103 Little Rock, Arkansas 72223	(501) 688–1624 (501) 664–6923 Fx awahlstrom@spp.org
Member	Jerry D. Rust President	Northwest Power Pool Corporation 7505 N.E. Ambassador Place Portland, Oregon 97220	(503) 445–1074 (813) 445–1070 Fx jerry@nwpp.org
Member	James Useldinger Manager, T&D System Operations	Kansas City Power & Light Co. PO Box 418679 Kansas City, Missouri, 64141	(816) 654–1212 (816) 719–9718 Fx jim.useldinger@kcpl.com
Observer	Stan Kaplan Specialist in Energy Policy	Congressional Research Service 101 Independence Avenue, SE Washington, D.C. 20540–7450	(202) 707–9529 (301) 452–1349 Fx skaplan@crs.loc.gov

North American Electric Reliability Corporation Staff Roster

North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Telephone: (609) 452-8060
Fax: (609) 452-9550

Reliability Assessment and Performance Analysis

Mark G. Lauby	Director of Reliability Assessment and Performance Analysis	mark.lauby@nerc.net
Jessica Bian	Manager of Benchmarking	jessica.bian@nerc.net
Aaron Bennett	Engineer of Reliability Assessments	aaron.bennett@nerc.net
John Moura	Technical Analyst, Reliability Assessment	john.moura@nerc.net
Rhaiza Villafranca	Technical Analyst, Benchmarking	rhaiza.villafranca@nerc.net
Ryan Stewart	Intern, Reliability Assessment and Performance Analysis	

Contributing NERC Staff

Michael Assante	Vice President and Chief Security Officer	michael.assante@nerc.net
Tim Roxey	Manager of Critical Infrastructure Protection	tim.roxey@nerc.net
Kelly Ziegler	Manager of Communications	kelly.ziegler@nerc.net
John Seelke	Manager of Planning	john.seelke@nerc.net
Karen Spolar	Committee and Event Services Administrator	karen.spolar@nerc.net
Elizabeth Crouse	Administrative Assistant	elizabeth.crouse@nerc.net

to ensure
the reliability of the
bulk power system