NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2008 Long-Term Reliability Assessment

2008-2017

to ensure the reliability of the bulk power system

October 2008

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Current draft in bold

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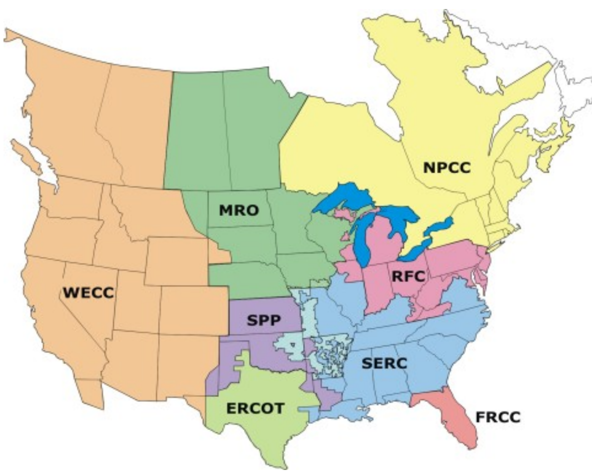
NERC's Mission

The North American Electric Reliability Corporation's (NERC) mission is to ensure the reliability of the bulk power system in North America. To achieve this objective, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future transmission and generation adequacy; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants that comprise its various committees and sub-groups. It is subject to oversight by governmental authorities in Canada and the United States (U.S.).[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system according to eight regional areas as shown on the map below[2]. 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, Mexico.



Note: The highlighted area between SPP and SERC denotes overlapping regional boundaries

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 the necessary legislation is adopted.

2 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.

Introduction

The *2008 Long-Term Reliability Assessment* represents NERC's independent judgment of the reliability and adequacy of the bulk power system in North America for the coming ten years. NERC's primary purpose in preparing this assessment is to identify areas of concern regarding the reliability of the North American bulk power system and to make recommendations for their remedy. The annual schedule for NERC's reliability assessments is found in Table 1.

This assessment is prepared by NERC in its capacity as the Electric Reliability Organization in the U.S. and parts of Canada.[3] NERC cannot order construction of generation or transmission or adopt enforceable standards that require expansion of these facilities, as that authority is explicitly withheld in the U.S. by Section 215 of the U.S. Federal Power Act[4] and in Canada by various provisions. In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

Table 1:
NERC's Annual Reliability Assessments

Assessment	Outlook	Published
Summer Assessment	Upcoming season	May
Long-Term Assessment	10 years	October
Winter Assessment	Upcoming season	November

The potential long-term impacts of the recent unprecedented events in global financial markets could have a significant effect on future electricity supply and demand projections that are not reflected in this special report. NERC will monitor these impacts and reflect them in its future assessments.

Assessment Preparation

NERC prepared the *2008 Long-Term Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS) under the direction of NERC's Planning Committee (PC) with additional review from the Operating Committee (OC).[5] The report is based on data and information submitted by each of the eight Regional Entities in March 2008 and periodically updated throughout the report drafting process.[6] This data and information is carefully vetted to ensure accuracy and consistency by NERC staff and RAS. Other data sources consulted by NERC staff are identified in this report.

[3] 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."

[4] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

[5] Unlike the Energy Information Administration's (EIA) Annual Energy Outlook (for example the 2008 report can be found at http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf), NERC's report focuses exclusively on bulk power system reliability with data and information provided by industry experts, representing a variety NERC stakeholders.

[6] See http://www.nerc.com/files/Adequate_Level_of_Reliability_Defintion_05052008.pdf for more background on reliability concepts used in this report.

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

Each region prepares its data and a self assessment. Each of the regional self-assessments is assigned to two to four RAS members from other regions for an in-depth and comprehensive review of the data and information. Reviewer comments are discussed with the regional entity's representative and refinements and adjustments are made as necessary. The regional self-assessments and data 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 and data is accurate, thorough, and complete. The *Reliability Trends* section is reviewed by the OC, while the entire document, including the regional self-assessments, is then reviewed in detail by the Member Representatives Committee (MRC) and NERC management. The report is endorsed by the PC before being submitted to NERC's Board of Trustees for final approval.

To further increase the transparency of the process and conclusions, NERC sponsored a public workshop designed to discuss preliminary findings with industry experts and participants, identify industry concerns, and solicit improvements. Key suggestions from this workshop are reflected in this final report. The presentations and notes from the workshop are posted on the NERC Web site.[7]

In the *2008 Long-Term Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[8]

- Supply and demand projections are based on industry forecasts submitted in March 2008. Regions were given an opportunity to reflect significant changes through the summer, but any subsequent demand forecast or resource plan changes may not be fully represented.
- Peak demand and capacity margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each regional self-assessment.
- Generating and transmission equipment will perform at historical availability levels.

[7] http://www.nerc.com/filez/ltra_workshop.html

[8] 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.

For planning and analytical purposes, it is useful to have an estimate not only of the expected of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, the Load Forecasting Working Group (LFWG) develops for each an upper and lower ten percent confidence band around the NERC regional demand and energy projections. This means there is an 80 percent probability that future demand and energy will occur within these bands. Concurrently, there is a ten percent chance future outcomes could be less than the lower band and a ten percent chance future outcomes could be higher than the upper band. The high and low bands around the demand forecasts are depicted in the charts with each region's self assessment

- Planned outages and future generation and transmission facilities are commissioned and in-service as scheduled and planned.
- Demand reductions expected from demand response programs will yield the forecast results, if and when they are called on.
- Other peak demand-side management programs are reflected in the forecasts of net internal demand.
- Firm electricity transfers between regions are contractually arranged and occur as projected.

Enhancements to the 2008 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 and directed it to develop recommendations and a plan for improvement. A number of the task force's recommendations[9] were incorporated into the *2008 Long-Term Reliability Assessment*, including:

1. Supply-side resource categories were enhanced to better assess and measure the certainty and risk of resource acquisition strategies and adequacy.
2. Collection of Demand-side Management data was expanded to include both projected Energy Efficiency and Dispatchable Demand Response.[10]
3. Both wind nameplate and on-peak capacity projections were collected.
4. Emerging issues and scenario analysis sections were added to identify risks and document risk assessment results. The scenarios for the 2009 LTRA are currently under development.
5. Reliability trends were compiled to provide indications of system use and the need for further investigations in future reliability assessments.

[9] For the full report, see http://www.nerc.com/files/Reliability%20Improvement%20Report%20RAITF%20100208.pdf, entitled, "*Data Collection for Demand-Side Management for Quantifying its Influence on Reliability: Results and Recommendations.*"
[10] ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/NERC_DSMTF_Report_040308.pdf

Progress Since 2007

In its *2007 Long-Term Reliability Assessment*,[11] NERC identified five "Key Findings" that could critically impact 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 regions as part of the Long-Term Reliability Assessment, NERC staff independent assessment of the results as well as industry trends, and other stakeholder input and comments.[12]

The magnitude of these issues necessitates complex planning and execution strategies whose impacts may not be realized for several years. As shown in Table 2, 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 electric system for the future. Based on industry progress made on 2007 *Key Findings*, NERC will either continue to highlight them through the *Key Findings* or *Emerging Issues* sections of this report, or will continue to monitor advancement.

Table 2: Progress on 2007 Key Findings

2007 Key Finding	Progress in 2008	2008 Status
1. *Long-Term Capacity Margins are still Inadequate*	▪ 4.2% improvement over 2007 ▪ Demand response decreases peak 1% by 2016 ▪ More resources required in some areas	▪ *Key Finding*
2. *Integration of Wind, Solar and Nuclear Resource Require Special Consideration in Planning, Design and Operation*	▪ Wind plant nameplate increased (145,000 MW of Proposed installed nameplate capacity) ▪ Nuclear plant projections increase 9,000 MW by 2017 ▪ Transmission vital for integration of resources in various planning stages across NERC.	▪ *Key Finding*
3. *High Reliance on Natural Gas in Some Areas of the U.S. Must Be Properly Managed to Reduce the Risk of Supply & Delivery Interruptions*	▪ Natural gas delivery remains a concern ▪ Regional measures taken	▪ *Emerging Issue*
4. *Transmission Situation Improves, But More Still Required*	▪ Projected mileage increase of 14% from last year ▪ More transmission needed to maintain bulk power system reliability and integrate new generation	▪ *Key Finding*
5. *Aging Workforce Still a Growing Challenge*	▪ Increased industry recognition and response ▪ NERC continues to support action and monitor industry progress	▪ *Monitoring*

[11] http://www.nerc.com/files/LTRA2007.pdf

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

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Capacity Resources & Margins Quick Reference Guide

Total Internal Demand (MW) — Total amount of electricity projected to be used at time of peak within a given system area

Net Internal Demand (MW) —Total Internal Demand reduced by dispatchable controllable (capacity) demand response.

Existing-Certain Capacity — Existing generation resources anticipated to be available, operable and deliverable to or into the region at the time of peak demand.

Existing-Uncertain Capacity — Existing generation resources which may be available, operable, and deliverable to or into the region at the time of peak demand. This category includes "mothballed" units and the "de-rated" portion of intermittent resources not included in Existing Certain.

Planned Capacity — Generation that has achieved certain regulatory and approval milestones (see pg. 273).

Proposed Capacity — Generation that is not in any of the above categories, but has passed certain planning milestones (see pg. 273).

Net Firm Transactions (MW) — Net of contracted firm interregional purchases (positive value) and sales (negative value).

Deliverable Internal Capacity — Sum of Existing Certain and Planned Capacity.

Net Capacity Resources (MW) — Deliverable Internal Capacity, less Transmission-Limited Resources, all Derates, Energy Only resources, and Inoperable resources; plus Net Firm and Expected Purchases/Sales.

Total Potential Resources (MW) — Net Capacity Resources, plus Existing Uncertain and Proposed Capacity, less Derates, plus the net of all Purchases/Sales.

Adjusted Potential Resources (MW) —Total Potential Resources with Total Proposed Capacity reduced (multiplied) by a confidence factor

Existing-Certain Capacity and Net Firm Transactions Margin (%) — Existing-Certain Capacity and Net Firm Transactions less Net Internal Demand; as a percent of Existing-Certain Capacity and Net Firm Transactions.

Net Capacity Resource Margin (%) — Net Capacity Resources reduced by the Net Internal Demand; as a percent of Net Capacity Resources.

Total Potential Resources Margin (%) — Total Potential Resources reduced by the Net Internal Demand; as a percent of Total Potential Resources

Adjusted Potential Resources Margin (%) — Capacity margin using the Total Potential Resources reduced (multiplied) by the confidence factor (percentage).

Target Capacity Margin (%) — Established target for capacity margin by the region or sub-region.

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

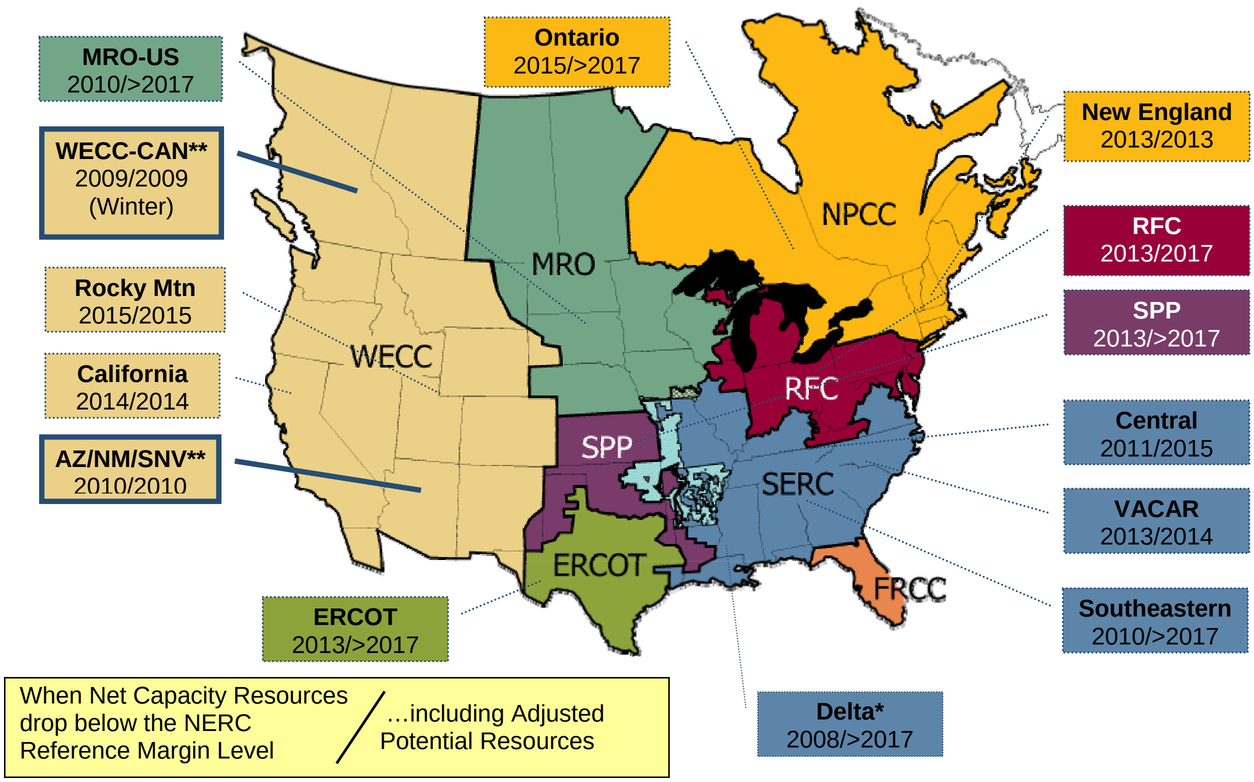
Key Findings for 2008-2017

1. Capacity Margins Improved, though Resources still Required

Capacity margins in many regions are improved compared to 2007 figures, due in part to significant increases in demand response and supply-side resources. Nevertheless more resources will be required to maintain reliability in Western Canada and the Desert Southwest areas in the coming years.

Many areas have shown improvement in projected capacity margins, due to changes in resource categorization, the establishment of forward capacity markets, or the addition of new resources. These areas include New England, California, the Rocky Mountain sub-region, Texas, and the Midwest. Figure 1 provides the 2008-2017 summer capacity margins in North America (unless noted as winter) to NERC's Reference Margin Level.[13]

Figure 1: Net Capacity and Adjusted Potential Resources compared to NERC's Reference Margin Level[14]



* Substantial amounts of existing capacity in SERC-Delta subregion are categorized as "uncertain" under NERC's 2008 capacity categories. Under this year's method, existing-uncertain generation is not counted towards Net Capacity Margin. Rather, it is included in the Adjusted Potential Capacity Margin. This generation is expected to be available to meet peak demand in the region despite its classification as "uncertain". We expect that clarification of definitions for 2009 will correct this issue

** Areas that may need more resources to meet their Target Margin Level or NERC Reference Margin Level.

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[13] The colors shown in this map serve to show the regional boundaries of reporting entities.

[14] 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 Capacity Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 13 percent capacity margin for predominately thermal systems and for predominately hydro systems, 9 percent.

Certain areas (See Figure 1), however, may still need additional resources in the near-term to ensure adequate capacity margins when comparing Net Capacity Resources margins to the NERC Reference Margin Level. Areas of most concern include: Western Canada (in winter) and the Desert Southwest. The outlook improves somewhat when including Adjusted Potential Resources, but Western Canada and the Desert Southwest margins are still a cause for concern.

Winter Net Capacity Resource Margins in Canada are projected to decrease. Offsetting additional supplies throughout the rest of Canada, Ontario's Net Capacity Resources for the 2017/18 Winter peak are 4,800 MW lower than 2008/2009 Winter, reflecting the planned retirements of 6,400 MW of coal-fired generation by the end of 2014. Much of this reduction is balanced with demand response and energy efficiency coupled with new renewable, gas-fired, refurbished and new-build nuclear resources.

Drivers

A number of factors have combined to affect resource adequacy for 2008. Marked improvement from 2007 in New England, for example, is directly due to newly operational mechanisms designed to add greater long-term planning visibility. Dubbed "forward capacity markets," these and similar mechanisms are being implemented in some parts of North America.

Supply-side additions have also contributed to improved margins, though substantial uncertainty exists for new resource construction. These additions are predominately gas-fired generating units (50%), but also include nearly 25,000 MW of coal plants still slated for construction despite recent trends in coal plant deferrals and cancellations,[15] 145,000 MW of nameplate wind, and 9,000 MW of new nuclear generation beginning to appear in the outer years.

Recent rulemaking activities of the U.S. Environmental Protection Agency (EPA) on the Clean Air and Water Acts and federal climate change legislative deliberations in the U.S., each discussed in the *Emerging Issues* section of this report,[16] could adversely affect both existing capacity (earlier retirements) and these planned capacity additions (deferrals and cancellations), which will, in turn, result in lower future capacity margins.

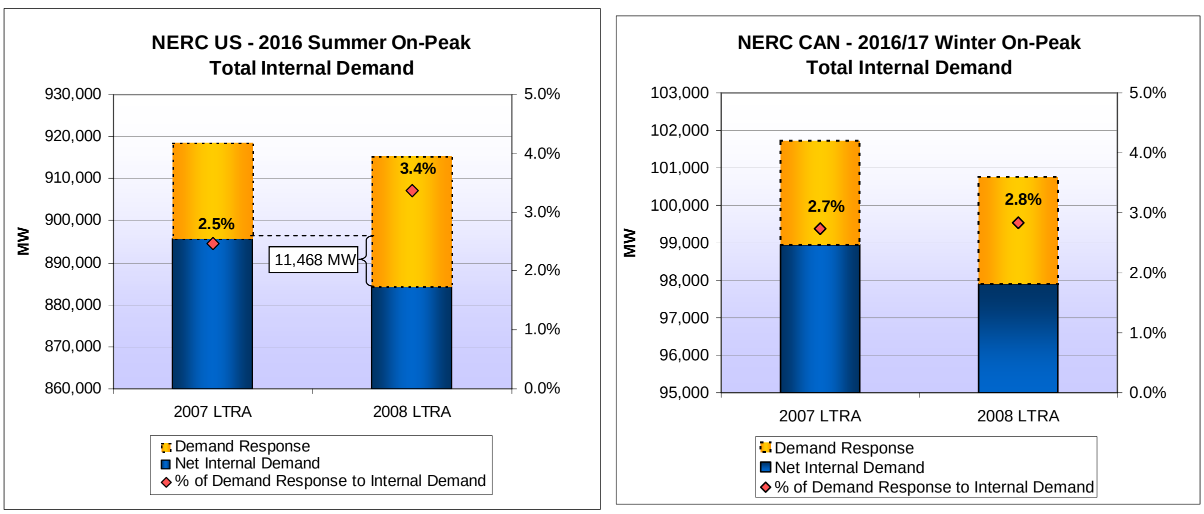
A significant decrease in projected demand growth in the U.S. also contributes to higher capacity margins over the ten year period. This is primarily due to an increase in projected demand-side management (DSM) which plays a key role in improving capacity margins over the ten years. Summer peak demand growth is projected to increase 16.6 percent for 2008-2017, compared to 17.7 percent forecast last year through the 2007-2016 period. This represents a reduction of 1.1 percent or almost one full year of growth (see Figure 2). An increase in projected dispatchable demand response is responsible for most of this reduction. Comparing last year's projections to this year for the summer of 2016, demand response accounts for 3.4 percent of Total Internal Demand in this year's report compared with 2.5 percent for last year (See Figure 2 below).

[15] OE NETL: http://www.netl.doe.gov/coal/refshelf/ncp.pdf

[16] See www.nerc.com for more information on the potential impacts on reliability of Climate Change Initiatives

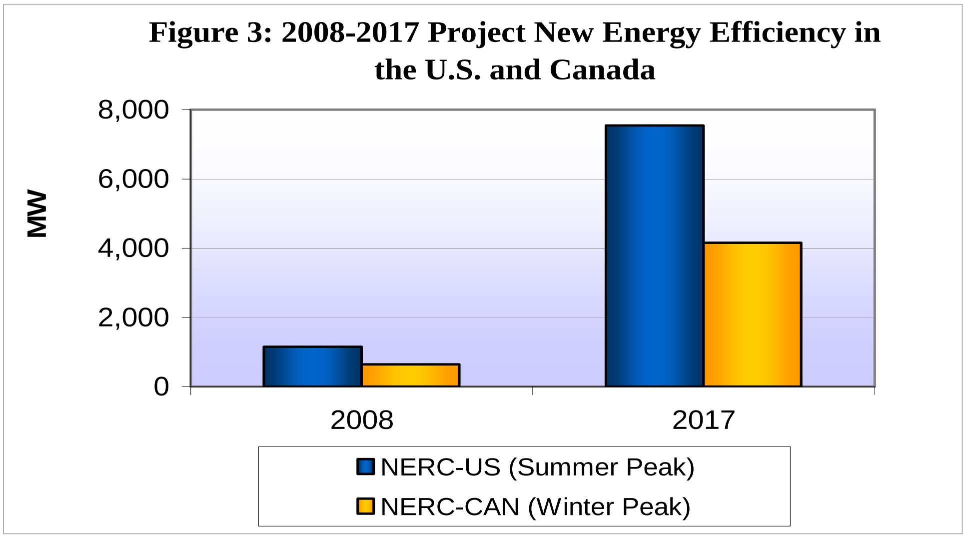
In Canada, winter peak demand is forecast to increase by over 6,500 MW or 7.2 percent during the next ten years, which is higher than the 6.5 percent growth forecast in last year's assessment. However, the total winter peak demand for both 2008/2009 and 2017/2018 are lower than last year's projections, due to lowered demand forecasts in Ontario and The Maritimes. Ontario[17] forecasts a 2008/09 winter demand decrease of 1,200 MW compared to the 2007/2008 winter peak demand and a decrease of 2,326 MW when comparing this year's ten-year forecast (2017/2018 winter) with last year's (2016/2017 winter). These reductions result from conservation and energy efficiency[18] programs, countering the expected 0.7 percent average annual growth.

Figure 2: Dispatchable Capacity Demand Response Resources for the U.S. (2016 Summer peak) and Canada (2016/17 Winter peak)



New energy efficiency is also projected to increase in both the U.S. and Canada. For example, for the summer peak, NERC-US grows over 6,000 MW during 2008-2017. During this same period, in Canada, Energy Efficiency is projected to grow by 3,000 MW for the winter peak (See Figure 3).

[17] Ontario is summer peaking. The 2017 Peak Summer forecast is 1,226 MW less than 2008 Summer peak.
[18] http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=320



Reliability Impacts

Capacity margins are measurements of the bulk power system's ability to supply the aggregate electric power and energy requirements of electricity consumers. Higher capacity margins indicate that the system is more capable of withstanding extreme weather, forecasting errors, system events, and unscheduled resource outages. Lower capacity margins can lead to reduced reliability. Those regions and sub-regions whose capacity margins are projected to fall below NERC's Reference Margin Levels in the next few years need to add resources quickly in order to maintain bulk power system reliability.

The electric industry is projected to increase its reliance on Energy Efficiency and Dispatchable Capacity Demand Response programs. To consistently validate and measure the results of the demand response programs, NERC is inaugurating a demand response event analysis system (Demand Response Data Task Force), expected to be launched in 2010.[19]

Conclusions and Recommendations[20]

- Regulators need to continue their support for the development of additional cost effective transmission resources, including equitable cost allocation guidelines for such resources. Further, they should revise their existing processes to expedite the licensing of cost effective transmission resources needed to maintain reliability.
- Formal markets should continue to pursue mechanisms to establish longer-range visibility of their resource needs.

NERC Actions

- Monitor the conditions in Western Canada and the Desert Southwest which may require additional resources in the near future.
- Improve categorization of projected supply-side and demand-side resources to enhance the analysis of capacity margin certainty and risk.

[19] See http://www.nerc.com/filez/drdtf.html for ongoing progress.
[20] The "Recommendations" for each of the Key Findings do not represent mandatory requirements, but rather NERC's independent judgment of those steps that will help improve reliability of the bulk power system of North America

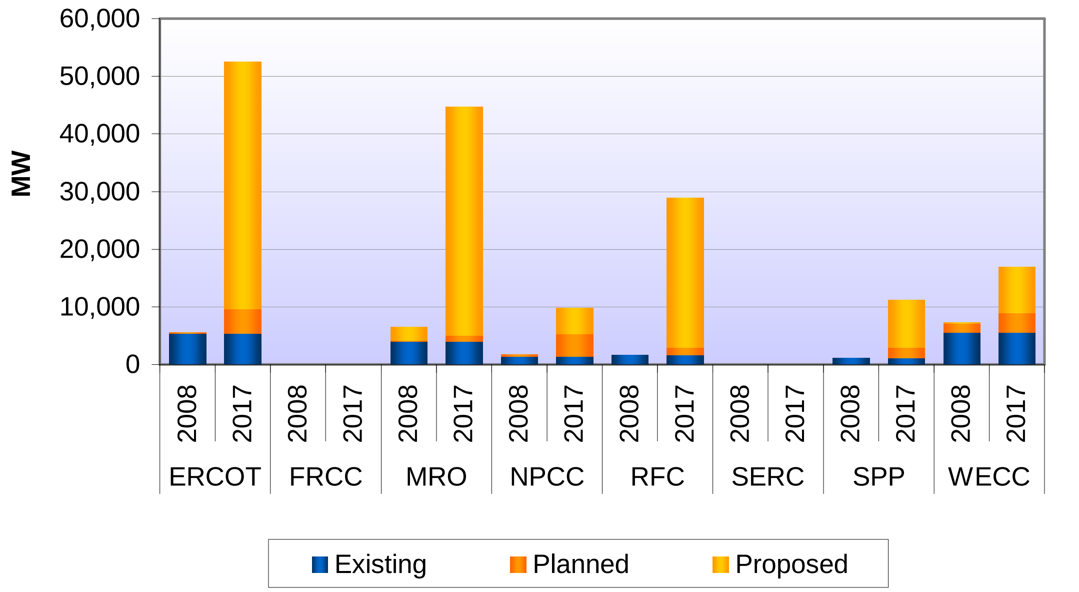
2. Wind Capacity Projected to Significantly Increase

Wind resources are growing in importance in many areas of North America as new facilities come online. With growing dependence on wind generation, it is vital to ensure that these variable resources are reliably integrated into the bulk power system.

As shown in Figure 4, 145,000 MW of nameplate new wind resources are Planned or Proposed over the next ten years. Though the bulk of these additions are categorized as Proposed resources raising the possibility that a number of these projects may be cancelled or reduced as developers make their final decisions, this projection still represents a dramatic increase in wind energy resources when compared to data received last year.

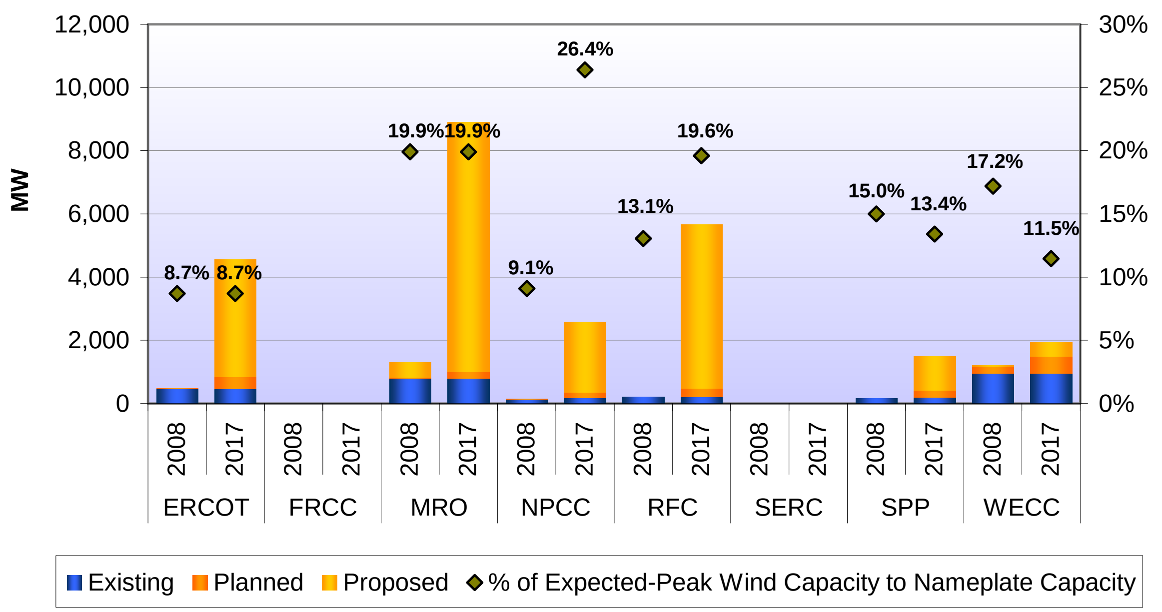
While other renewable resources are beginning to appear in forecasts (800 MW of Existing-Certain and 280 MW of Planned solar capacity resources were reported in WECC), wind generation has become the primary reported focus of renewable resource development in North America.

Figure 4: Projected Increase in Summer Wind Nameplate/Installed Capacity



Availability of capacity during times of peak demand (capacity on peak) is an important issue facing wind power when discussing reliability. Figure 5 shows the projected wind capacity during summer peak presented in megawatts (bars in Figure 5) and as a percentage of nameplate capacity (diamonds in Figure 5). These values vary significantly between regions (from 8.7 percent in ERCOT to 26.4 percent in NPCC) due in part to varying forecasting and planning methodologies currently under development.

Figure 5: Projected Increase in Existing, Planned & Proposed Summer On-Peak Wind Capacity



Drivers

Policy and regulations aimed at energy independence, climate change and green house gas emissions, whether already in place or still under consideration, seem to be the most significant drivers for development of new renewable resources. Renewable Portfolio Standards (RPS) currently in place in over 30 U.S. states, for example, require many utilities to acquire new renewable resources to meet up to 30% of their total energy portfolio over the next five to 15 years.[21] Supported by federal tax credits in the U.S., wind power has become the fuel of choice for these requirements due to the maturity of the technology and availability of suitable sites for development.

Reliability Impacts

The proposed level of commitment to renewable resources offers many benefits including a more diversified fuel mix and reduced emissions. But, just as with any new technology, certain challenges to reliably integrating wind into the system must be addressed.

Numerous studies have been conducted to study wind integration, notably the recently released report by the Department of Energy which suggests wind energy could provide for 20 percent of the U.S. electricity needs by 2030.[22] Though the level of penetration is the most studied factor, reliability considerations also include the size of balancing areas, improved system flexibility, ancillary service requirements, wind forecasting and transmission requirements.

NERC's Integration of Variable Generation Task Force has been studying the influence on reliability of accommodating large amounts of wind generation.[23] Preliminary conclusions of

[21] See *Emerging Issues* Section for more detail.
[22] http://www.20percentwind.org/
[23] http://www.nerc.com/filez/ivgtf.html

this NERC Task Force, concentrating on accommodate large amounts of variable generation (i.e. predominately wind) are:

- Forecasting of resources must be improved to manage wind uncertainty
- Flexibility of the bulk power system must be expanded to manage wind variability
- Transmission must be constructed to enable management of both the uncertainty and variability of wind resources.

Power system planners and operators are already familiar with a certain amount of variability and uncertainty, particularly as it relates to system demand and, to a lesser extent, with conventional generation. Output from wind generation, however, is not as dispatchable as conventional resources. With limited operating history, planners and operators are adjusting their activities to accommodate large amounts of wind while maintaining bulk power system reliability.

Consistent methods are needed, for example, to determine wind on-peak capacity to ensure uniform measurement of its contribution to capacity margins. Three approaches are in current use: 1) Effective Load Carrying Capability (ERCOT), historical performance (i.e. SPP) and deploying a flat percentage (i.e. Midwest ISO predominately located in MRO and RFC areas). These different approaches provide widely different results seen in Figure 5.

Conclusions and Recommendations

- Regulators and policy makers must support the development of cost effective transmission resources, including equitable cost allocation guidelines for the delivery of both remotely located wind resources and ancillary services (such as spinning reserve and frequency response) to demand centers where such resources and/or services are deemed necessary and beneficial.
- Coordinated effort is needed to better determine appropriate calculations for measuring the availability of wind on peak.

NERC Actions

- Assist the Integration of Variable Generation Task Force in the completion of its report incorporating specific, actionable recommendations.
- Review the regions’ renewable resource scenario analyses to be incorporated in the *2009 Long-Term Reliability Assessment.*

3. More Transmission Needed to Maintain Bulk System Reliability and Integrate New Generation

Though total miles of transmission additions have increased when compared to last year's assessment, much more transmission will be required to reliably integrate projected location-constrained resources such as wind, nuclear, clean coal, and others into the bulk power system.

The total number of transmission miles is projected to increase by 9.5 percent (15,700 circuit-miles) in the U.S. and 7.4 percent (3,400 circuit-miles) in Canada over the next ten years (See Table 3).

This represents 1,700 more circuit-miles projected to be added in the U.S. and 1,000 more circuit-miles in Canada over the coming ten-year period when compared to projections in last year's report.

More resources and investment will be needed, however, to maintain reliability and integrate new resources as aging infrastructure is replaced and changes are needed to the transmission system topology. New generation supply is projected to outpace transmission development by nearly two times – with Total Potential Resources projected to grow by 21 percent.[24]

Further, many new supply resources are likely to be located remote from demand centers (i.e. wind generation) and location-constrained to those areas. The amount of transmission required to integrate these resources is significant. In Texas alone, for example, over 2,300 miles of new bulk transmission was recently approved for construction to transport power from new wind resources in West Texas to population centers like

Table 3: Planned Transmission Circuit Miles > 200 kV

		2007 Existing	2008-2012 Additions	2013-2017 Additions	2017 Total Projection
United States					
ERCOT	-	8,792	269	623	9,684
FRCC	-	7,201	349	239	7,789
MRO	-	15,939	1,075	1,258	18,273
NPCC	-	6,805	252	16	7,073
NPCC	New England	2,660	242	16	2,918
NPCC	New York	4,145	10	-	4,155
RFC	-	26,203	1,471	154	27,828
	RFC-MISO	7,229	687	21	7,937
	RFC-PJM	18,209	784	133	19,126
SERC	-	32,295	1,676	753	34,724
	Central	3,270	257	-	3,527
	Delta	5,065	253	73	5,391
	Gateway	1,952	57	-	2,009
	Southeastern	9,503	459	448	10,410
	VACAR	12,505	650	232	13,387
SPP	-	7,683	672	21	8,376
WECC	-	59,061	5,305	1,591	65,957
	AZ-NM-SNV	10,418	1,310	713	12,441
	CA-MX US	14,437	1,587	119	16,143
	NWPP	24,875	1,669	663	27,207
	RMPA	6,122	739	96	6,957
Total-U.S.		163,979	11,069	4,655	179,704
Canada					
MRO	-	6,693	392	931	8,016
NPCC	-	29,106	933	285	30,324
	Maritimes	2,174	-	103	2,277
	Ontario	11,316	420	-	11,736
	Quebec	15,616	513	182	16,311
WECC	-	10,700	703	153	11,556
Total-Canada		46,499	2,028	1,369	49,896
Mexico					
WECC	CA-MX Mex	674	238	102	1,014
Total-NERC		211,152	13,335	6,126	230,614

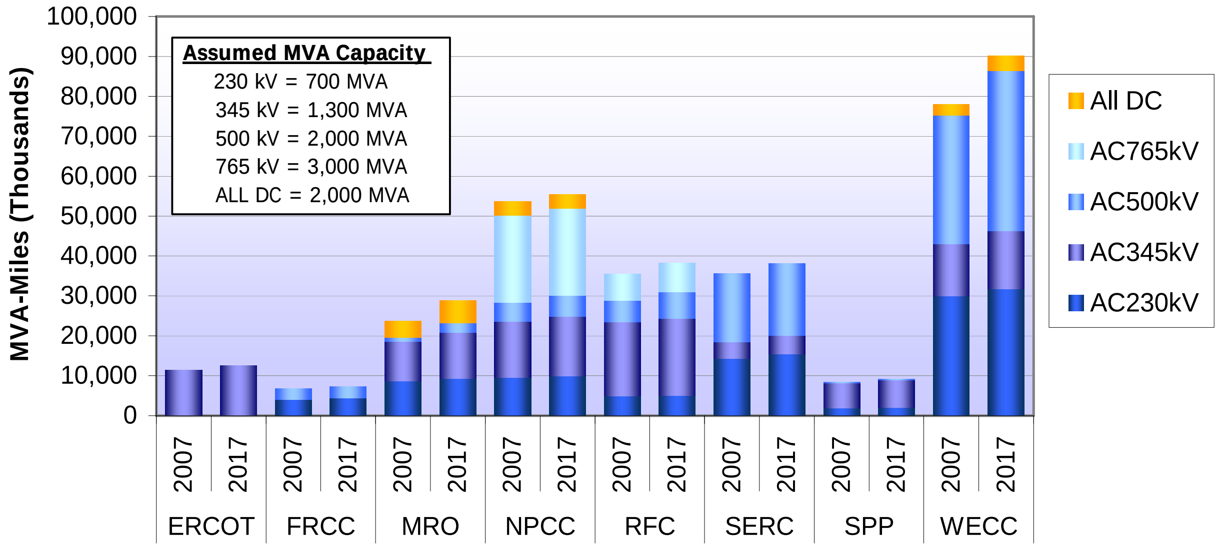
[24] NERC does not collect transmission additions with the same granularity as supply-side resources. This comparison assumes the mileage reported includes Proposed transmission additions which is compared to Proposed Capacity additions.

Dallas, Houston, Austin, and San Antonio in the eastern part of the state.[25] This increase in 345 kV facilities is not reflected in this report's ERCOT data as it was submitted in March, 2008 which was prior to regulatory approval of these facilities.

The *Major Transmission Projects > 200 kV* section includes examples of potentially significant transmission additions, which are projected to improve reliability and/or system efficiencies. The projects were identified on a regional basis as vital to regional reliability during and beyond 2008–2017.

In order to provide another view of the breadth of investment requirements and capacity installation under consideration, the collective capacity of existing and planned regional transmission was weighted by their total miles and average MVA capacity by operating voltage in Figure 6. Though this comparative does not entirely measure the bulk power system reliability benefits and increased capability of individual facility additions,[26] it provides insights into transmission capacity additions.

Figure 6: NERC-Wide Total Existing and Planned Lines: MVA-1000 Miles



Perhaps most notable are the 765kV additions planned in RFC. This approximately 240 mile project, expected to be in-service in 2012, will bring a strong source of power into Maryland area by reducing the west-to-east power flow on the existing PJM 500 kV transmission paths while providing significant benefits to the constrained area of Washington, DC and Baltimore.

Drivers

Lagging investment in transmission resources has been an ongoing concern for a number of years. More investment is required, as each peak season puts more and more strain on the transmission system, especially in constrained areas such as California and Desert Southwest of the U.S.

[25] ERCOT's CREZ analysis (http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf Data not included in the submittal as this approval for transmission occurred after March 31, 2008.

[26] For example, short lines in parallel may add more capability than long lines in series.

The process to site new transmission continues to be difficult, time consuming and expensive due to local opposition and environmental concerns especially when lines are planned to cross state borders. Negotiations still delay and, in some cases, stop needed projects from being built. As a result, transmission permitting, siting, and construction can take significantly longer (i.e. 7-10 years) than permitting, siting, and construction of generation.

Positive steps are being taken in some states and provinces to expedite certain key projects, and the U.S. federal government now has back-stop authority for lines planned within DOE defined National Interest Electric Transmission Corridors (NIETC). A number of studies are also ongoing to provide advanced planning for facilities.[27]

Reliability Impacts

Transmission lines are the critical link between generation and customers. As demand grows and generation is built in areas remote from the demand, more capacity on the transmission system is needed to meet demand. Congestion on transmission lines, as more and more power is moved over them, can have a significant impact on reliability. As these lines reach their capacity, for example, they are less able to make up the difference when neighboring lines are forced out of service due to equipment failure, severe weather, or maintenance. Under-investment in transmission puts additional strain on existing resources, raising the risk of system disturbances, lengthening restoration time when outages do occur, and limiting access to remote generation.

Reflecting this importance, NERC should expand its understanding of projected transmission resource acquisition strategies being employed throughout North America. Therefore, the categorization of transmission additions should be considered to fully appreciate transmission resource requirements.

Conclusions and Recommendations

- Regulators need to continue their support for additional transmission resources. Further, they should revise their existing processes to expedite the licensing of transmission projected needed to maintain reliability.
- The projects identified in the *Major Transmission Projects > 200 kV* section and their associated in-service dates are vital to maintain regional bulk power system reliability and/or system efficiencies.

NERC Actions

- Continue to assess and report on the reliability impacts of integrating new variable generation and nuclear resources into the bulk power system.[28]
- Enhance data collection to increase the granularity and gradation of certainty of planned and proposed transmission projects.
- Provide information and support to NERC's stakeholders on the need for new transmission in North America.

[27] For example, Joint Coordinated System Plan Study (JCSG) (http://www.spp.org/publications/2007%2011%2001%20JCSP%20Stakeholder%20Meeting%20Presentation.pdf), the EHV Overlay Study (http://www.nerc.com/docs/pc/ras/EHV_Overlay_Overview_NERC_FERC_LTRA_Workshop_FINAL_81007.pdf), A Vision of The Next Interstate (www.nerc.com/docs/pc/ras/NERC_2008_LTRA_WS_30-31July08_presentations.zip), and WECC's Transmission Expansion Planning Policy Committee (http://www.wecc.biz/documents/library/board/TEPPC/TEPPC%20Charter.pdf)

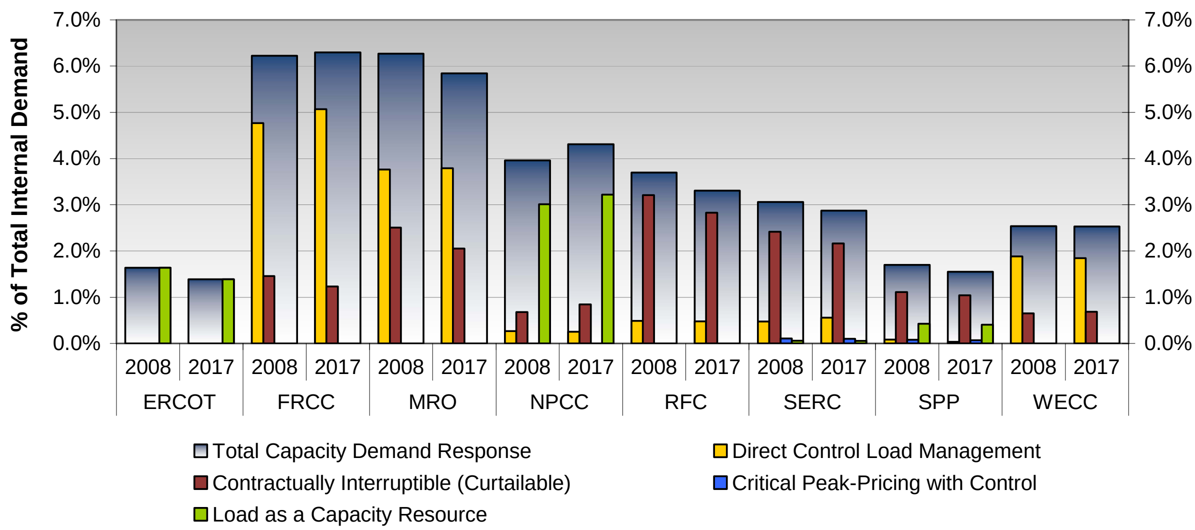
[28] NERC expects to issue a special report in December 2008 on the reliability requirements for integrating variable generation into the bulk power system.

4. Demand Response Increasingly Used to Meet Resource Adequacy Requirements

Demand response programs increased significantly in this year's projections. The long-term sustainability of these impacts will need to be monitored closely as these programs are used to meet reliability requirements more frequently.

Significant increases in demand response programs over the next ten years are projected to reduce growth in demand and provide ancillary services across North America. As shown in Figure 7, Capacity Demand Response,[29] as a percentage of demand, is increasing in FRCC (over 6% of demand) and NPCC (up to 4% of demand). In other regions, the ratio of demand response to demand declines somewhat, as demand response additions do not quite keep pace with demand growth. Though a suitable comparison to last year's report measuring relative gains is not possible due to improvements in NERC's data collection, these figures are both significant and encouraging.

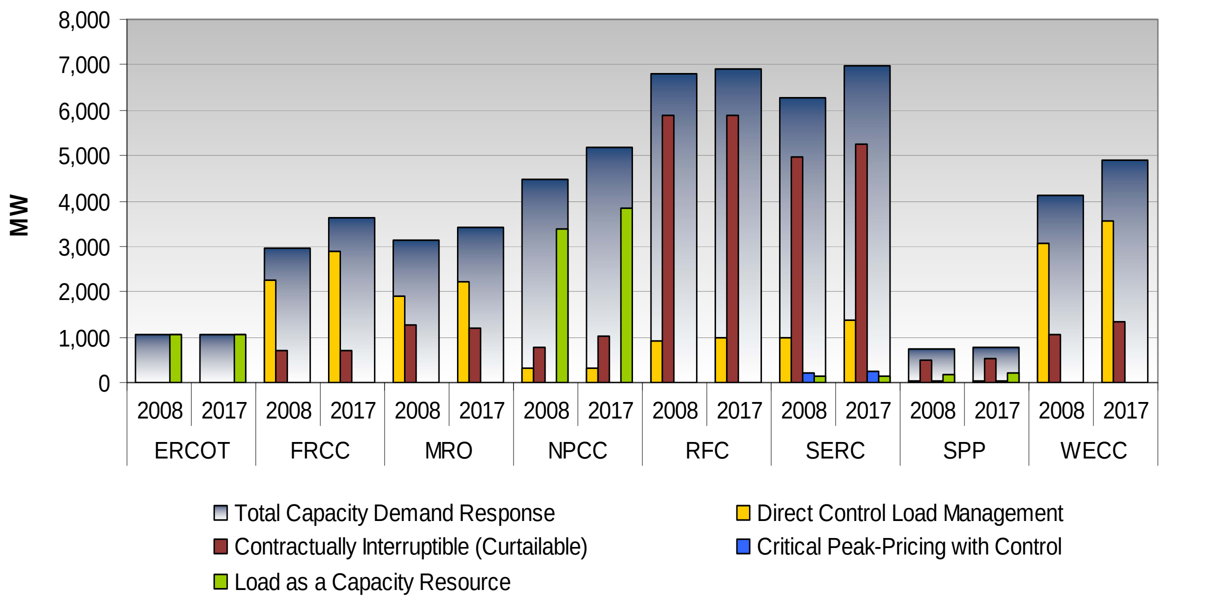
Figure 7: Capacity Demand Response as a % of Summer Peak Demand



The total NERC-wide Capacity Demand Response for summer peak demand reduction grows from 29,000 MW in the summer of 2008 to 32,500 MW in the summer of 2017. Figure 8 shows the projected increases in dispatchable demand response by region.

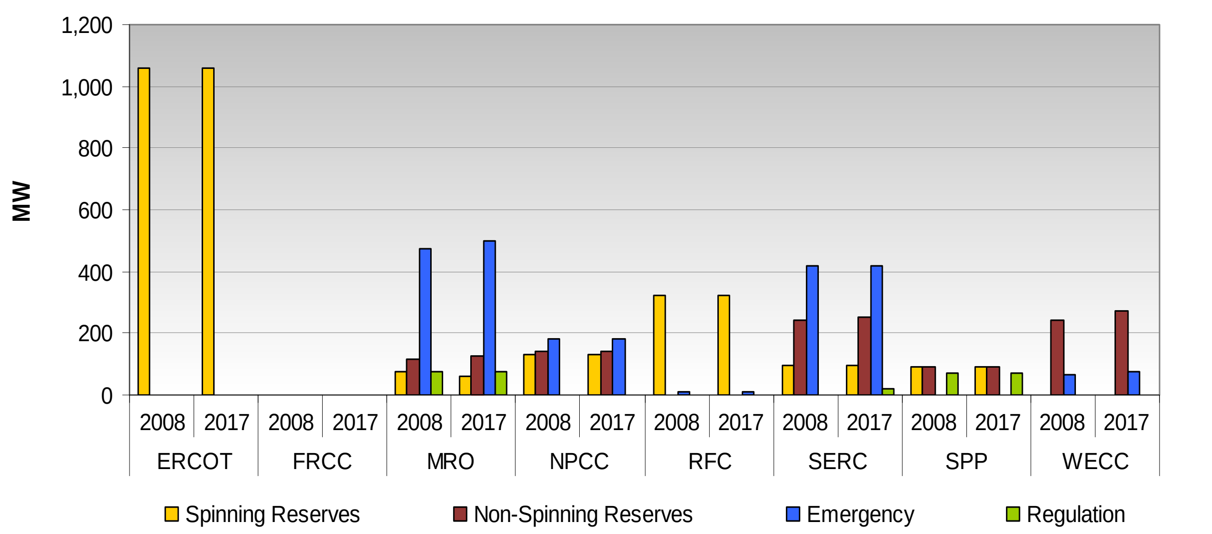
[29] See the *Capacity, Demand and Event Definitions Section* of this report for detailed definitions of demand response.

Figure 8: Capacity Demand Response (MW) - 10 Year Projection



The total NERC-wide demand response used for Ancillary Demand Response during the summer peak remains about constant at just under 4,000 MW. NERC regional comparison is shown in Figure 9.

Figure 9: Ancillary Demand Response (MW) - 10 Year Projection



Drivers

Federal, state, and provincial policy makers and regulators are increasingly interested in improving the overall availability and efficiency of demand response resources to help address climate change issues.[30] In addition, the electric industry is increasingly using demand response as an effective and efficient capacity resource, on equal footing with generation. In areas with structured markets, for example, demand response resources are now allowed to enter capacity markets, either through curtailment service providers or directly from individual customers. Several state commissions are also considering ways to earn a rate of return on demand response investments similar to new build generation. Florida's commission, for example, has had such a mechanism in place for a number of years which has supported the high adoption of the resource in the state.

Reliability Impacts

Demand response will become a critical resource for maintaining system reliability over the next ten years. Though demand continues to grow, new development of supply-side options are becoming increasingly limited – many coal plants have been deferred or cancelled, nuclear plants are becoming more and more expensive, and transmission lines increasingly difficult to site. Further, demand response also has an important role to play as more variable resources (such as wind) are added to the system. Variable resources, for example wind generation, often need a "dance partner" which can provide operational flexibility to maintain reliability during resource down-ramps that can be associated with them. Demand response can provide all or a portion of the flexibility required for this integration.

As demand response is relied upon more heavily to meet firm demand in these capacities, however, more coordination between demand response programs, system operators, and system planners is needed to fully assess the resource's availability, characteristics, and constraints. For example, as dispatchable demand response programs are increasingly used as non-emergency resources, the probability and frequency of their dispatch will also likely increase. Voluntary participation in these programs may decline as a result of this higher usage, causing the program to suffer "response fatigue." If this occurs, system reliability could be affected as other resources may not be built or available in time to provide the ancillary services or energy required. In many cases, dispatchable demand response resources have not yet been tested to meet system reliability requirements at these potentially higher dispatch frequencies.

Conclusions and Recommendations

- Additional demand-side resources could be an effective option to preserve system reliability over the next ten years. In addition, they may facilitate the integration of renewable and variable resources.
- Potential reliability impacts of broad-scale use of demand response resources must be better understood by industry and regulators.
- Better measurement and verification techniques will be needed to measure and track actual availability of demand response under various system conditions.

[30] Some examples of Federal, State and Provincial activities can be found in the following reports: http://www.ferc.gov/legal/staff-reports/demand-response.pdf, http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf, http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=320 & http://www.narucmeetings.org/Presentations/National%20Action%20Plan%20on%20Demand%20Response%20-%20NARUC-R3.pdf

NERC Actions

Anticipating the growth in demand response as part of the seasonal and long-term reliability assessments, the NERC Planning Committee, in coordination with the North American Energy Standards Board (NAESB), initiated two activities:

1. Develop and maintain a categorization scheme while collecting projected information.[31]
2. Design and implement a demand response event analysis system.[32]

The recommendations from the first activity were approved by the NERC Planning Committee and results included in this report. The Demand Response Data Task Force was formed by the Planning Committee in order to measure and validate demand response event data and evaluate potential reliability concerns. The demand response event data collection scheme and report are to be completed in early 2009.

[31] http://www.nerc.com/docs/pc/drdtf/NERC_DSMTF_Report_040308.pdf
[32] http://www.nerc.com/filez/drdtf.html

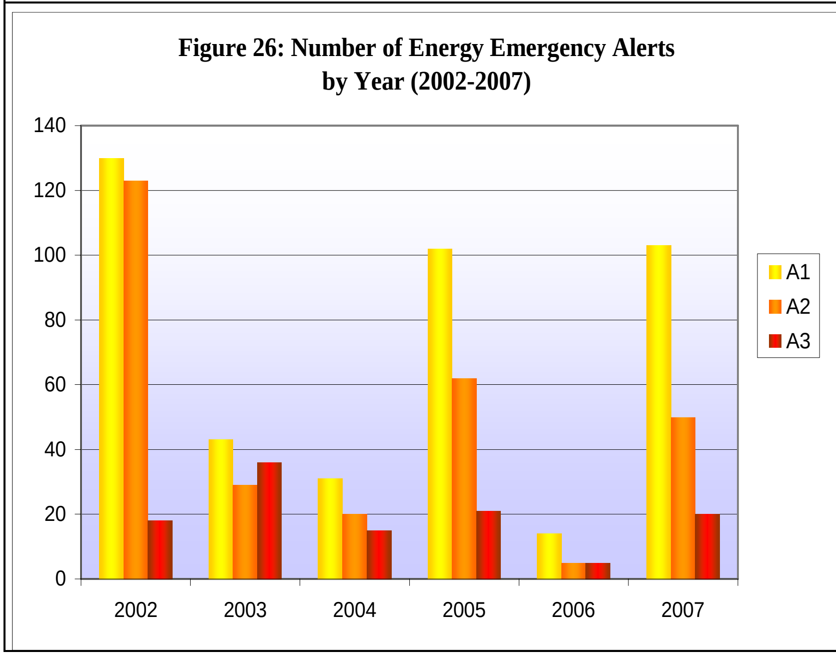
5. Bulk Power System Adequacy Trends Emphasize Maintenance, Tools and Training

NERC performed its initial analysis of reliability metrics from the last six years and concluded that the drive towards suitable maintenance, operating tools and training must continue. It is vital that these metrics be further refined and the trends analyzed so that root causes can be addressed.

There are two basic, functional components of bulk power system reliability: operating reliability and adequacy.[33] NERC has developed preliminary metrics measuring bulk power system reliability and, though these metrics require further refinement for future reliability assessments and are primarily limited to the Eastern Interconnection[34], they can provide valuable insights for root cause analysis and bulk power system planning goals. [35]

For example, Energy Emergency Alerts, shown in Figure 10, are issued when electricity supplies in a given area become insufficient to serve demand, remain high in the Eastern Interconnection during the last six years. In 2007, there were 20 occasions when firm customer load interruption was imminent or in progress (Category A3).[36]

Figure 10: Number of Energy Emergency Alerts by Year (2002-2007)



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.
- a. Public appeals to reduce demand.
- b. Voltage reduction.
- c. Interruption of non-firm end use loads per contracts.
- d. Demand-side management.
- e. Utility load conservation measures.

Category A3: Firm load interruption imminent or in progress.

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[33] See the *Capacity, Demand and Event Definitions* Section

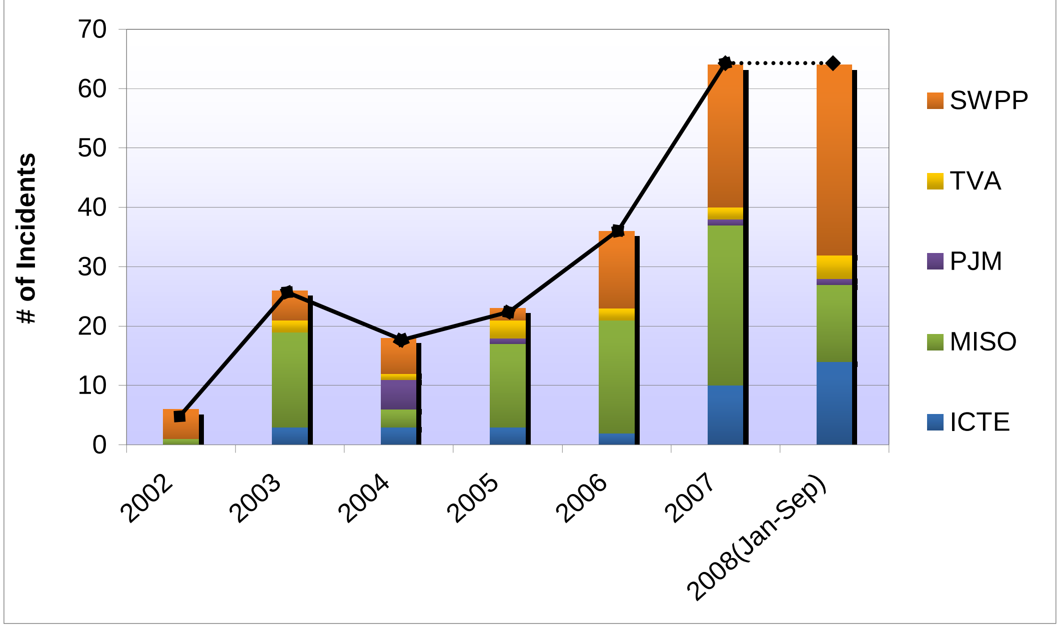
[34] http://en.wikipedia.org/wiki/Eastern_Interconnection

[35] This is the inaugural year for incorporating reliability metrics in the Long-Term Reliability Assessment. Available data for this assessment is solely from the Eastern Interconnection.

[36] The current definition for Category A2 includes the operation of demand-side resources as a capacity and emergency event, while current industry practice includes the resource as part of normal, non-emergency operations. The categories for capacity and emergency events based on Standard EOP-002-0, therefore, require revision to account for higher use of demand response as a capacity and ancillary resource. See http://www.nerc.com/docs/pc/drdtf/NERC_DSMTF_Report_040308.pdf, entitled, "*Data Collection for Demand-Side Management for Quantifying its Influence on Reliability: Results and Recommendation*" as well as the *Capacity Demand and Event Definitions* section of this report for NERC's demand-side management definitions and categorization.

One measure of bulk transmission congestion, used in parts of the Eastern Interconnection of North America, is Transmission Loading Relief (TLR) requests, which have increased during the last six years. In some cases, the over-scheduling of electricity transactions requires the issuance of TLRs, which is how system operators maintain system loadings within reliability limits. Reallocation and curtailment of bulk transmission service to meet System Operating Limits and Interconnection Reliability Operating Limits are increasing (See Figure 11).[37]

Figure 11: TLR's Level 5b: 2002 - Sep 2008 [38]



While TLR actions in and of themselves do not directly indicate a lowering of reliability, their higher use of these requests by some regional coordinators such as Interdependent Coordinator of Transmission for Entergy (ICTE), Southwest Power Pool (SWPP) and the Midwest Independent Service Operator (MISO) requires further investigation. It is necessary to understand the drivers behind this perceived transmission congestion to determine if it represents a reliability or economic issue. If it is increasing because the transmission system is being fully used to optimize economic dispatch, congestion may not impact bulk power system reliability. If congestion is occurring because needed transmission capacity is not available to serve firm load, then this may be an indicator of reliability concerns.

Application of TLR represents one method used in the Eastern Interconnection to relieve potential or actual loading. However, differences exist on how areas approach congestion management. For example, WECC uses an Unscheduled Flow Mitigation Plan as an equivalent load relief procedure for use in the Western Interconnection.[39] In market structures, redispatch is

[37] See the *Operational Reliability* Section

[38] SPP implemented its Energy Imbalance Market (EIS) on February 1, 2007. Since the implementation of the EIS Market, SPP has experienced an increase in the number of TLR events primarily due to its operating protocols. SPP's market protocols require that the SPP Reliability Coordinator issue a TLR event every time congestion is experienced in the market footprint.

[39] This procedure has been accepted by FERC and adopted by NERC Standards: http://www.nerc.com/files/IRO-STD-006-0.pdf. WECC USFMP: http://www.wecc.biz/documents/library/UFAS/UFAS_mitigation_plan_rev_2001-clean_8-8-03.pdf

commonly used as an efficient measure to reduce congestion in transmission systems. MISO[40] and PJM[41] have Locational Marginal Pricing (LMP) markets which run a security constrained dispatch models to determine the lowest cost generation dispatch without exceeding transmission limitations. Similarly, ERCOT employs a flow-based/zonal approach to manage forward markets and congestion.[42]

Drivers

Building and operating infrastructure to meet growing demand remains a challenge. Therefore, the industry has developed new operational approaches to effectively use existing bulk power system assets. These actions can reduce the bulk power system's ability to withstand unexpected system outages. To maintain reliability, the industry has improved maintenance practices, developed new operational tools and reinforced operator training.

Recognizing the need to measure reliability trends, NERC's Planning and Operating Committees jointly organized the Reliability Metrics Working Group (RMWG) to develop and improve reliability metrics. Specific activities will include:

- Development of general metrics for the characteristics of an Adequate Level of Reliability
- Definition of reliability measures, including formulae or methods for their calculation
- Identification of data collection and reporting guidelines
- Recommend root cause analysis

Conclusions and Recommendations

- Industry must continue to emphasize the importance of bulk power system maintenance, new tools and well-trained operators.

NERC Actions

- 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.
- NERC should revise its Emergency Preparedness and Operations Standard EOP-002-0 removing demand-side management as a characteristic for identifying an Energy Emergency Event (i.e. Category A2).

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[40] More information on MISO's congestion management procedures can be found in the *2007 STATE OF THE MARKET REPORT FOR THE MIDWEST ISO* at*:* http://www.midwestiso.org/publish/Document/24743f_11ad9f8f05b_-7b890a48324a/2007%20MISO%20SOM%20Report_Final%20Text.pdf?action=download&_property=Attachment

[41] PJM's congestion management procedures can be found in the *2007 STATE OF THE MARKET REPORT FOR THE PJM INTERCONNECTION* at http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2-sec7.pdf

[42] ERCOT's congestion management procedures, entitled *2007 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS* http://www.puc.state.tx.us/wmo/documents/annual_reports/2007annualreport.pdf

Emerging Issue Assessment & Scenario Analysis

Each year, the 10-year *Long-Term Reliability Assessment* (LTRA) 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. Risk assessment and study of emerging reliability issues can identify a set of scenarios which may require deeper analysis. Once complete, these scenarios can then be compared to the reference case to measure any significant changes in bulk power system reliability.

Emerging Issue Risk Assessment

Background - Risk assessment of 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 LTRA ten-year study period, 2) Impacts reliability no sooner than three years into the future to allow sufficient time for analysis, and 3) Impacts the reliability across at least one regional footprint and is not a local or sub-regional reliability issue.

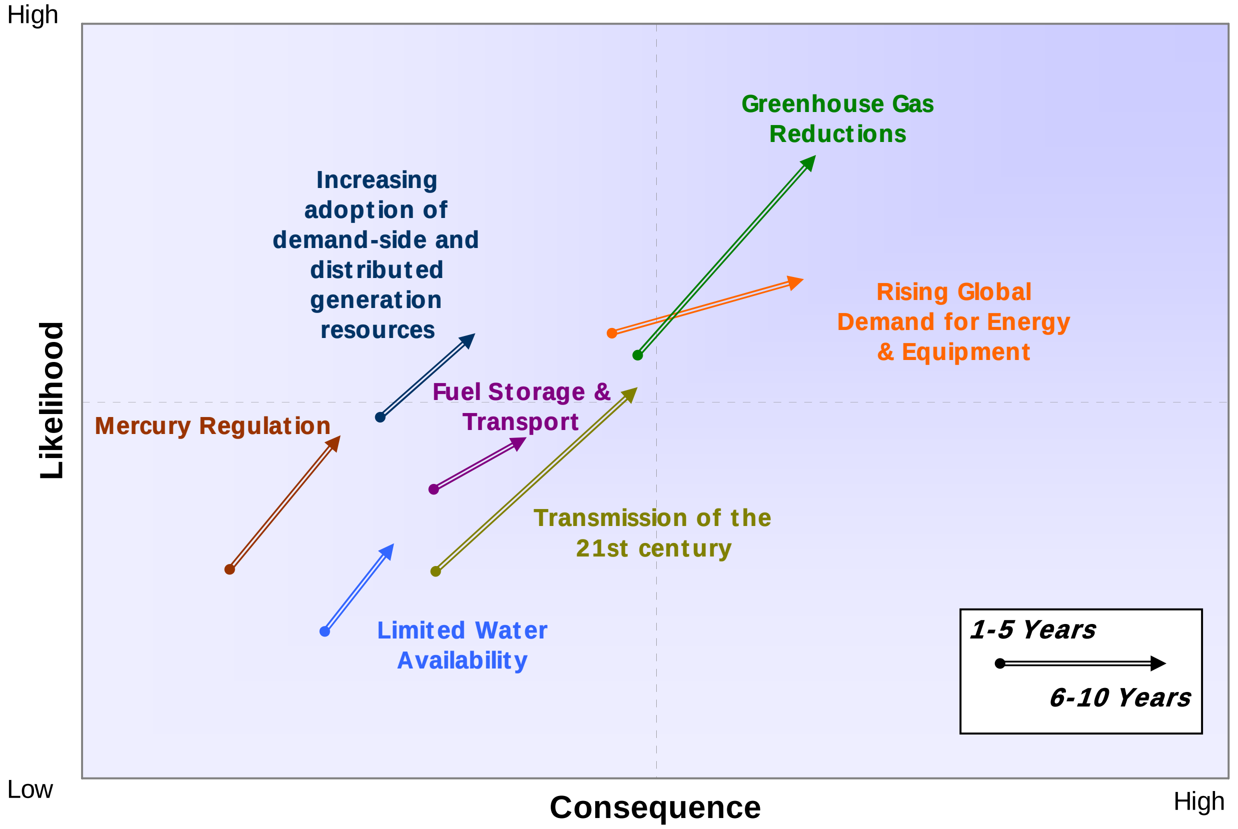
NERC's Reliability Assessment Subcommittee and staff identified seven emerging issues for use in the Planning Committee's (PC) Risk Assessment:

1. Greenhouse gas reductions
2. Fuel storage and transportation
3. Rising global demand for energy and equipment, increased off-shore manufacturing of raw and finished materials
4. Increased adoption of demand-side and distributed generation resources
5. Replacing, upgrading and adding transmission infrastructure for the 21st century, including enhance cyber security protections
6. Water availability and use
7. Mercury emissions regulations

Risk Assessment – After endorsing the aforementioned emerging issues, the PC prioritized the resulting emerging issues based on risk, defined as their likelihood and consequence, and categorized each issue as high, medium, or low. This risk assessment was performed for two timeframes: 1-5 years and 6-10 years.

Ranking and Risk Evolution - The risk assessment survey was completed by industry stakeholders represented on the NERC Planning Committee. Figure 12 below provides the risk vectors for the seven emerging issues for the 1-5 year and 6-10 year timeframe.

Figure 12: Emerging Issues Risk Evolution: 1-5 Year & 6-10 Years



Three emerging issues show increased acceleration into the high likelihood and the high consequence quadrants: 1) Greenhouse Gas Reductions, 2) Rising Global Demand for Energy & Equipment, and 3) Transmission of the 21st Century. None of the seven emerging issues showed a decrease in probability or impact in the 6-10 year timeframe. The risk assessment confirmed the sentiment of the Reliability Assessment Subcommittee that all seven emerging issues are important to NERC and the industry

Finally, PC members individually identified potential emerging issue gaps, naming seven additional concerns not ranked: 1) Plug-in Hybrid Vehicles, 2) Impact of wide-scale transmission 'back-bone' infrastructure, 3) Major Transmission Improvements for new Nuclear Plants, 4) Increasing Use of Special Protection Systems to avoid transmission construction, 5) Once through cooling limitations, 6) Hydroelectric dam removal, and 7) Air emissions and offset regulations. These issues may be explored in more detail in future reliability assessments.

Descriptions and reliability considerations for each of the emerging issues are discussed below. A broader view of environmental regulation impacts was added to place the air and water issues into perspective.

They are grouped as:

- Potential Environmental Regulation Could Impact Resource Adequacy
  - Greenhouse Gas Reductions
  - U.S. Clean Water Act: Cooling-Water Intake Structures
  - U.S. Clean Air Act: Interstate Rule and Mercury Rule
- Fuel Transportation and Storage
- Rising global demand for energy & equipment, increased off-shore manufacturing of raw & finished materials
- Increased adoption of demand-side and distributed generation resources
- Replacing, upgrading and adding transmission infrastructure for the 21st century, including enhanced cyber security protections
- Water availability and use

Finally, a status report of the Scenario Analysis for the 2009 LTRA is discussed in this section.

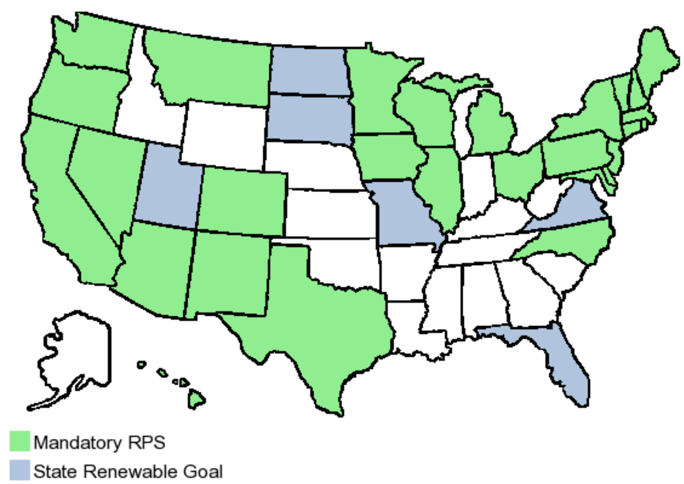
Potential Environmental Regulation could Impact Resource Adequacy

A number of ongoing environmentally-driven regulatory issues could, in sum, have a significant effect on resource adequacy in the U.S., namely Greenhouse Gas Reductions and climate change initiatives, the U.S. Clean Water Act: Cooling Water Intake Structures[43] and the U.S. Clean Air Act: Interstate and Mercury Rules. Understanding the reliability implications of potential legislation and regulations is vital to ensuring that the bulk power system remains reliable during and after implementation.

Greenhouse Gas Reductions

Background: The drive to reduce greenhouse gas emissions is gaining momentum throughout North America. Regulations such as Renewable Portfolio Standards are being promulgated by individual states and provinces, with over thirty states adopting similar regulations[44] (Figure 13[45]).

Figure 13: Snapshot of Renewable Portfolio Standards (RPS) in the U.S.



In 2006, coal provided almost 50% of the electric energy production[46] in the US and approximately 20% in Canada[47] in 2003. Natural gas is the cleanest fossil fuel in terms of air quality and carbon emissions, emitting up to 60 percent less carbon dioxide than coal. However, the magnitude of these benefits depends on the source of the natural gas and other factors, such as plant efficiency. Burning natural gas instead of coal at electricity-generating units to reduce greenhouse gas emissions involves important tradeoffs related to economic, environmental, infrastructure, and fuel supply considerations. Converting existing capacity to natural gas poses substantial challenges due to fuel supply constraints, changes to infrastructure, and economic considerations. [48]

The prospect for federal regulation in the U.S. continues to grow as numerous climate change bills are proposed in the House and Senate. A recent United States Supreme Court decision[49] determined that greenhouse gases regulation could fall under the purview of the U.S. Environmental Protection Agency (EPA). The U.S. EPA is inviting comment from all interested parties on options and questions to be considered for possible greenhouse gas regulations under

[43] http://www.catf.us/advocacy/legal/CWIS/RiverkeepervEPA%20P2%2004-6692-ag_opn.pdf
[44] http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm or more detailed resource maps at: http://www.pewclimate.org/what_s_being_done/in_the_states/nrel_renewables_maps.cfm
[45] The Florida Public Service Commission (FPSC) Renewable Portfolio Standard is currently under development
[46] http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html
[47] http://www.canelect.ca/en/Pdfs/HandBook.pdf
[48] http://www.gao.gov/new.items/d08601r.pdf
[49] http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf

the Clean Air Act. EPA has issued an advance notice of proposed rulemaking (ANOPR) to gather information and determine how to proceed.[50]

To lay the foundation for future action, NERC gathered stakeholder perspectives on this issue, asking them to identify potential impacts climate change initiatives may have on bulk power system reliability. NERC will be issuing a special report on these findings in the coming weeks.[51]

U.S. Clean Water Act: Cooling-Water Intake Structures

Background: Some thermal (coal, nuclear and gas) generation plants use substantial volumes of cooling water and are located on large water bodies or high flow-rate rivers. Many of these facilities currently use once-through cooling systems: drawing large volumes of water from the ocean, lake, or river to cool plant equipment and returning the used, warmer water back into the body of water immediately after use.

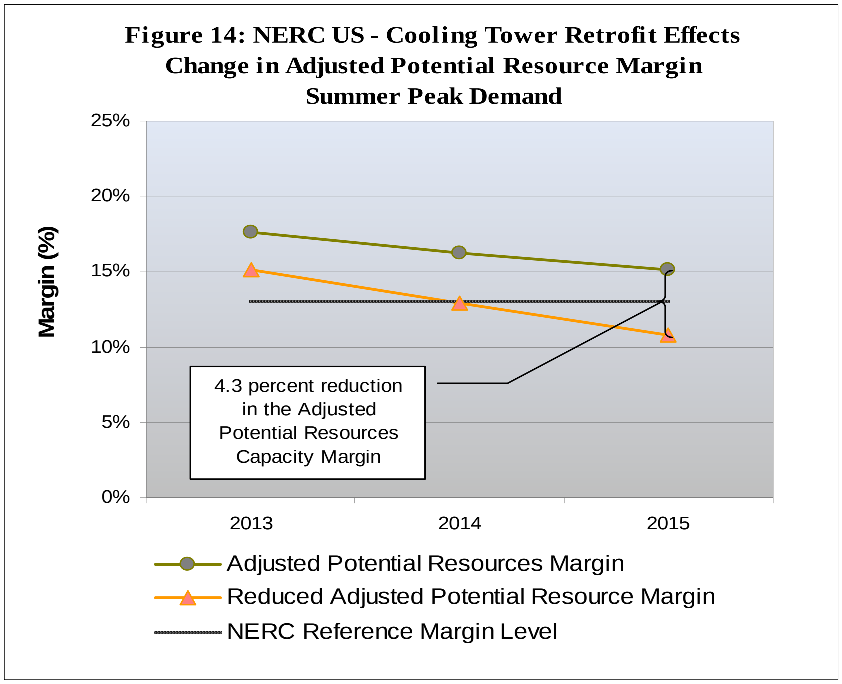
Section 316(b) of the Federal Water Pollution Control Act (FWPCA), more commonly known as the Clean Water Act, regulates thermal discharges to the surface waters in the U.S. The temperature of the water discharged to the receiving water body must be kept at a level such that thermal discharges do not adversely affect wildlife in and on that water body, commonly accomplished by dilution.

Thermal generation is impacted by two of the three phases promulgated by EPA 316(b):

- Phase I set standards for cooling water intake structures at new facilities.
- Phase II set standards for existing power plants.[52]

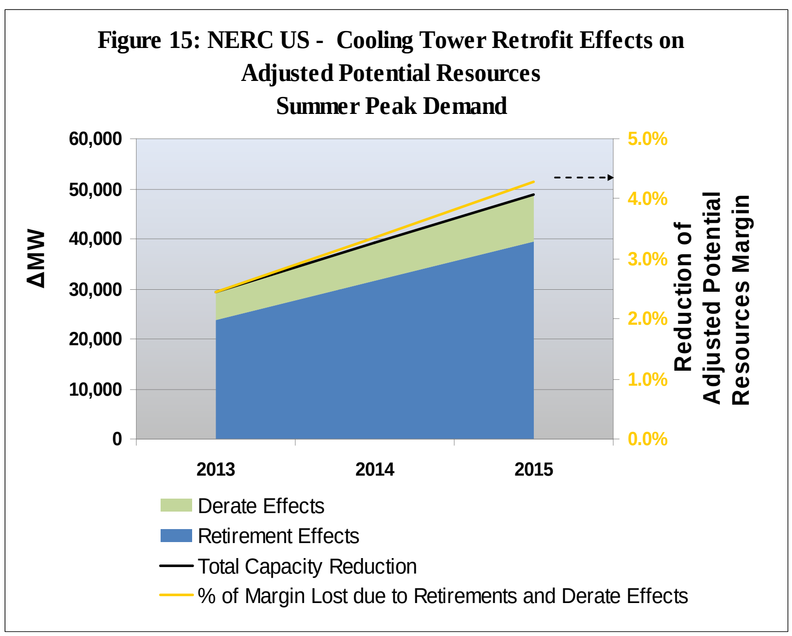
Phase II regulations required that large existing power plants withdrawing 50 million gallons per day or more and using at least 25 percent of the water withdrawn for cooling purposes must comply with requirements to minimize impingement and entrainment of aquatic life in the water intake structures. In 2004, the final rule provided several compliance alternatives. Based on a January 2007 decision by the Second U.S. Circuit Court of Appeals, EPA suspended its Phase II implementation[53] and is considering a new rulemaking. Those units with once-through cooling systems may be required to retrofit with closed loop cooling systems. The cost of such retrofits may result in some units retiring earlier than expected. Further, for plant retrofitting, there is an ancillary load required to serve the closed-loop cooling equipment, resulting in a de-rating of the unit's net output capability.

[50] http://www.epa.gov/climatechange/anpr.html
[51] See www.nerc.com
[52] http://www.epa.gov/waterscience/316b/phase2/devdoc/
[53] http://www.epa.gov/waterscience/316b/phase2/implementation-200703.pdf
† Adjusted Potential Resource Margins are subject to change, as updated capacity information is expected.
‡ Adjusted Potential Resources for WECC US include the AZ-NM-SNV subregion (approx. 37,000 MW). However, this subregion was unaffected in the NERC Special Reliability Assessment.



Reliability Considerations: In conjunction with the U.S. Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability and Office of Fossil Energy, NERC completed a Special Reliability Assessment measuring the Adjusted Potential Resource Capacity Margin implications of Section 316(b) Phase II rules.[54] DOE provided NERC a listing of vulnerable units (totaling approximately 240 Gigawatts). This information was supplemented by identifying those units that were expected to retire during the study time frame, along with permitting dates.

Summer peak capacity margins and demand data from the 2008-2017 Long-Term Reliability Assessment were used to establish a *Reference Case*. To reflect the potential EPA rulemaking timeframe, the summer peak Adjusted Potential Resource Capacity Margins for 2012 through 2015 were compared to the capacity margin impacts with assumed unit retirements and ancillary load increases.



NERC reviewed the impact of either retrofitting units with existing once-through-cooling systems to closed-loop cooling systems (4% reduction in nameplate capacity) or unit retirements (capacity factors less than 35 percent) on NERC-US and regional capacity margins for 2012-2015. Based on a worst case view, NERC-U.S. Adjusted Potential Resources may be reduced by over 48,000 MW, approximately 39,000 MW due to retirements and 9,000 MW due to increased unit auxiliary loads. This reduction has the effect of lowering the Adjusted Potential Resource Capacity Margin by 4.3 percent (see Figures 14 & 15).

[54] See http://www.nerc.com/files/NERC_SRA-Retrofit_of_Once-Through_Generation_090908.pdf for details and assumptions

Table 4 indicates the 2015 summer peak capacity margin reductions for each of the affected NERC-U.S. regions/subregions. The most significant reductions in capacity margin occur in California, ERCOT, New England, and the Delta Subregion of SERC, with each of these areas experiencing more than a 10 percent reduction in their capacity margins. These regions may require additional resources to accommodate the potential retirements/retrofits from the Section 316(b) Phase II action.

Table 4: 2015 Summer Peak Capacity Margin Reductions

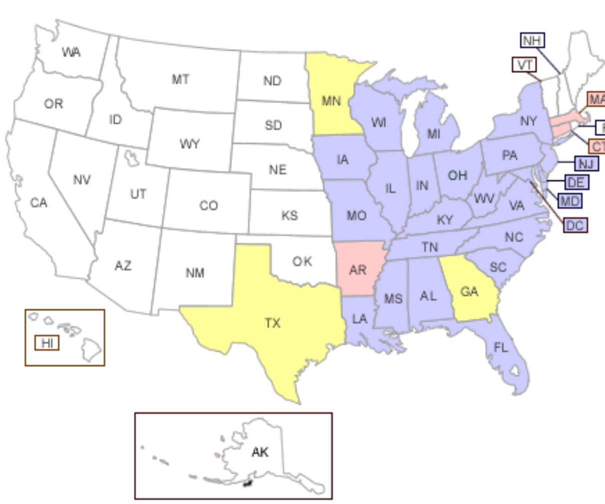
	Adjusted Potential Resources (MW)	Reduction due to Retirement (MW)	Derate due to Retrofit (MW)	NERC Reference Margin Level	Adjusted Potential Resources Margin	Margin Reduction	Reduced Margin
United States							
WECC - CA-MX US†	72,293	10,137	289	13.2%	12.7%	14.7%	-2.0%
NPCC - New England	31,673	2,827	428	13.0%	10.0%	10.3%	-0.3%
ERCOT	86,436	10,919	542	11.1%	15.9%	12.9%	3.0%
NPCC US	72,750	6,481	990	13.0%	13.3%	9.9%	3.4%
WECC US† ‡	176,944	10,177	314	12.3%	11.1%	5.6%	5.5%
NPCC - New York	41,077	3,654	561	13.0%	15.9%	9.6%	6.3%
SERC - VACAR	78,182	553	1,032	13.0%	11.0%	1.8%	9.2%
WECC - RMPA†	15,609	40	0	10.5%	10.2%	0.2%	10.0%
SERC - Central	54,548	0	949	13.0%	12.6%	1.5%	11.0%
SERC - Delta	41,259	4,266	466	13.0%	21.5%	10.2%	11.4%
RFC	230,062	3,339	2,863	12.8%	14.5%	2.4%	12.1%
SERC	269,599	6,054	3,307	13.0%	15.6%	3.0%	12.5%
SERC - Southeastern	66,675	675	357	13.0%	13.9%	1.4%	12.6%
MRO US	55,582	529	612	13.0%	15.1%	1.8%	13.3%
FRCC	63,170	1,267	454	13.0%	18.7%	2.3%	16.4%
WECC - NWPP†	51,861	0	25	11.9%	16.9%	0.0%	16.8%
SPP	63,700	817	257	12.0%	24.1%	1.3%	22.8%
SERC - Gateway	28,935	560	502	13.0%	28.8%	2.7%	26.1%
Total - NERC US	**1,018,243**	**39,583**	**9,339**	**13.0%**	**14.7%**	**4.3%**	**10.4%**

These capacity reductions could also result in additional transmission congestion. Detailed system transmission studies may be needed to determine the full extent of bulk power system reliability impacts resulting from the reduction of this significant amount of generating capacity.

U.S. Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR)

Two Clean Air Rules have the potential to impact capacity margins in the U.S. It is vital to understand potential plant retirements, ancillary demands of retrofit equipment and impact on bulk power transmission to fully understand the potential reliability impacts.

Figure 16: CAIR Coverage in the U.S.



Background: The U.S. EPA issued the Clean Air Interstate Rule (CAIR) in March 2005. CAIR is meant to reduce ground-level ozone and/or fine particles that might migrate across state boundaries. The Clean Air Interstate Rule covered 28 eastern states and

Washington D.C.[55] (see Figure 16). CAIR permanently placed a cap on emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) in the eastern U.S. by using an interstate cap and trade program deployed only in those states covered by the interstate mechanism.

In July, 2008, the U.S. Court of Appeals voided the current version of the CAIR and remanded it back to EPA[56], noting that their approach – region wide caps with no state specific quantitative contribution determinations or emission requirements – was flawed and required EPA to redo its analysis. The court also agreed that EPA must tailor pollution cuts in upwind states with the level of impacts on downwind jurisdictions. EPA is reviewing the Court's decisions and evaluating its impacts.

Closely related to CAIR, the EPA Clean Air Mercury Rule (CAMR) requires coal-fired plants to reduce their emissions of mercury. In December 2000, the U.S. EPA issued a "regulatory determination" under the 1990 Clean Air Act Amendments that regulation of mercury is "appropriate and necessary" for coal- and oil-fired power plants. Title III of the Amendments introduced the Maximum Achievable Control Technology (MACT) standard as a level of control. In March 2005, EPA issued its final Clean Air Mercury Rule (CAMR) for coal-based power plants. The CAMR used a market-based cap-and-trade approach to require emissions reductions in two phases: a cap of 38 tons in 2010, and 15 tons after 2018, for a total reduction of 70 percent from current levels. Facilities would have to demonstrate compliance with the standard by holding one "allowance" for each ounce of mercury emitted in any given year. In the final rule, EPA stated that regulation of nickel emissions from oil-based plants is not "appropriate and necessary."

In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion in a case, which was initiated by 15 states and other groups, challenging the CAMR and EPA's decision to "de-list" mercury as a hazardous air pollutant. The Court held that EPA's reversal of the December 2000 regulatory finding was unlawful[57]. The Court vacated both the reversal and the CAMR, and sent the CAMR back to EPA for reconsideration. As a result of the Court's decision, it is likely that EPA will develop a MACT standard, which would require every oil- and coal-based power plant to install mercury-specific controls.

A new EPA rulemaking could take several years to finalize and might not require emission reductions for more than five years. In the meantime, states are also developing their own Mercury standards that are at least as stringent as the EPA MACT standard.

Reliability Considerations: Much like meeting the requirements of Section 316(b) of the Clean Water Act mentioned above, compliance with CAIR and CAMR may require the owners of existing plants to face economic decisions to:

- Retire plants earlier than expected.
- Retrofit plants, which can increase ancillary loads

In either case, capacity margins would be reduced, increasing the need for more resources to meet resource adequacy requirements.

55 http://www.epa.gov/cair/index.html
56 http://www.epa.gov/cair/pdfs/05-1244-1127017.pdf
57 http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf

Fuel Transportation & Storage

The interdependence of the electric, gas, coal, and – to an extent – oil industries will continue to play a role in the adequacy of electricity supply in North America.

Background: The physical capacity for natural gas transportation and storage is emerging as an issue with greater potential implications for the adequacy of electricity supply than in recent years due to the increasing concerns regarding global warming and the increasing likelihood of legislation to reduce CO_2 emissions. Such legislation could create incentives for the construction of more new natural gas-fired capacity as a "bridging" technology to displace energy from existing coal-fired generation until new low-carbon electricity production technologies become commercially viable. The drivers toward a carbon-constrained future focus this discussion on natural gas transportation and storage as a potential weak reliability link associated with significant increases in gas-fired generation.

In 2006, natural gas-fired generation produced 20% of the electricity in the United States while representing 41% of the installed summer generating capacity. Coal-fired generation produced 49% of the electrical energy in North America and represented 32% of the installed summer capacity. Heavy and light oil is primarily used as a back-up fuel for natural gas. Oil-only fired capacity is negligible and total oil generation represented less than 2% of the electricity produced in 2006.[58]

Transportation and storage for coal, residual oil and distillate fuel oils have not been, nor are expected to be, an electric power reliability concern, as explained below.

- One significant disruption in rail transportation occurred in 2005 for the delivery of coal from the Powder River Basin (PRB), a region in southeast Montana and northwest Wyoming. The coal in this region has low sulfur and low ash content, and about 40% of the coal used in power plants at that time came from the PRB. Coal from the region is moved on a single rail system comprising three tracks that are jointly owned by the Union Pacific and Burlington Northern Santa Fe railroads. In 2006, the joint owners of the PRB rail system received the required approvals to add a fourth track.
- While fuel inventories at some coal plants reached extremely low levels in 2005, the PRB delivery disruptions did not impact electric reliability. Many utilities, however, did incur higher costs for the use of alternative fuels.
- Despite the 2005 PRB coal delivery disruption, the reliability aspects of coal transportation and storage are generally excellent.[59]

Residual (heavy) and distillate (light) oil are typically delivered by barge to power plants located along the Atlantic and Pacific coasts. Supply disruptions have not occurred in recent decades and the reliance on these fuels has dropped significantly since the repeal of both the Natural Gas Policy Act of 1978 and the Power Plant and Industrial Fuel Use Act of 1979 which eliminated the prohibitions against the significant use of natural gas as an electricity sector fuel.

[58] http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html

[59] Note that Midwest U.S. experienced severe flooding in 2008, and this caused fuel transportation delays, primarily with delivery of coal by rail. This year's floods are being compared to the 1993 floods. Both are either 100 or 500 year occurrences that have occurred within 15 years. It is too early to conclude that flooding is an emerging issue that needs to be considered.

Hydro is another primary energy source that can influence the adequacy of electricity supply. For areas that are heavily dependent upon hydro-electric generation, it has been observed that droughts can create severe strains on alternative fossil fuel resources and delivery infrastructure that may either not be robust or which atrophied during periods of favorable hydro conditions.

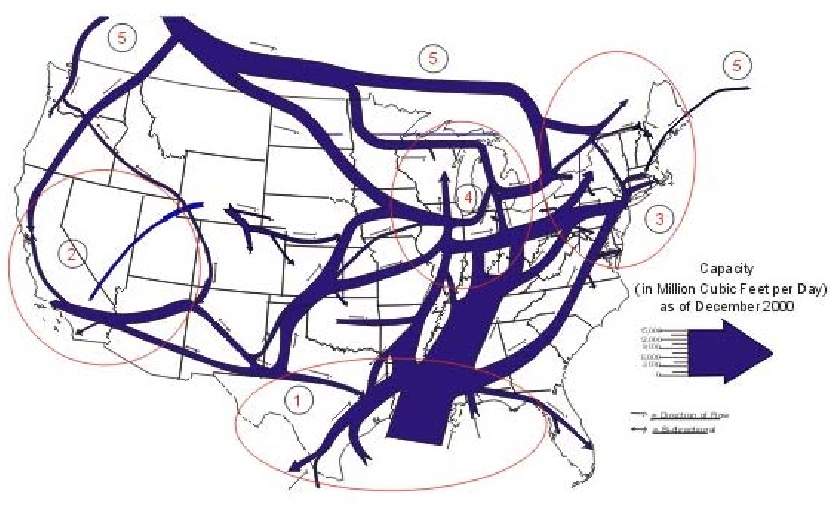
> *The California Energy Crisis of 2001 was largely precipitated by the onset of drought conditions in the Pacific Northwest after a decade of relatively high hydro conditions. Since California depends on imports from the Northwest to satisfy some of its adequacy needs, these drought conditions exerted stress on the coal and gas markets and the physical generation and delivery infrastructure. The failure of a key natural gas compressor station exacerbated the crisis as did the lack of opportunities for maintenance on natural gas-fired facilities and the concerns of making and receiving payments for generation in a dysfunctional electricity market.*[60]

Natural Gas Transportation:

The U.S. has several major natural gas production basins[61], and an extensive natural gas pipeline network. There are also numerous pipeline connections between the United States and Canada, and almost 95 percent of U.S. natural gas imports come from Canada. Major connections join Texas and northeastern Mexico, with additional connections to Arizona and between Baja California, Mexico, and California, U.S. Infrastructure growth in the Baja California region is expected.

A large portion of natural gas pipeline capacity within the United States is directed from major production areas of Texas and Louisiana to markets in the Western, Northeastern, and Midwestern regions of the country, as illustrated in Figure 17. In the past ten years increasing levels of gas from Canada have targeted these markets as well.

Figure 17: U.S. Natural Gas Pipeline [62]

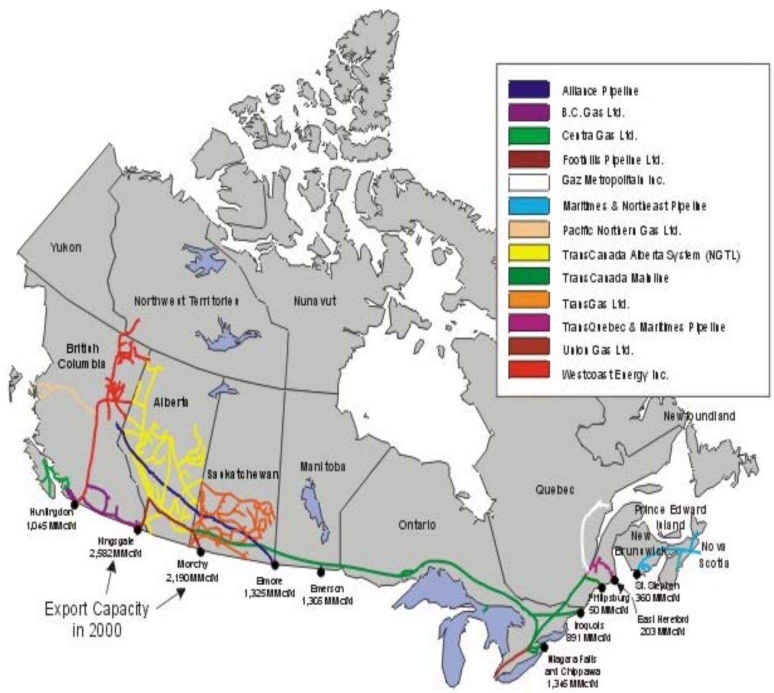


[60] http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/process.html
[61] Excepted from http://www.eia.doe.gov/emeu/northamerica/enginfr2.htm#_VPID_1
[62] http://www.eia.doe.gov/emeu/northamerica/fig35.jpg

Canada has an extensive natural gas pipeline network, including several major interconnections with the United States. Alberta is the dominant producer, though Nova Scotia is increasing its production. Canada is the world's second largest natural gas exporter after Russia. Figure 18 illustrates the pipeline system in Canada.

Natural gas is delivered by pipeline and, unlike electricity grids, natural gas pipelines do not demand the nearly instantaneous balancing of injections and withdrawals since the pipelines themselves have some storage capacity. While daily injections and withdrawals by customers are monitored by pipeline operators, pipelines typically have customers "true-up" their BTU injection and withdrawal differences ("imbalances") on a monthly basis.[64]

Figure 18: Main Canadian Natural Pipelines[63]



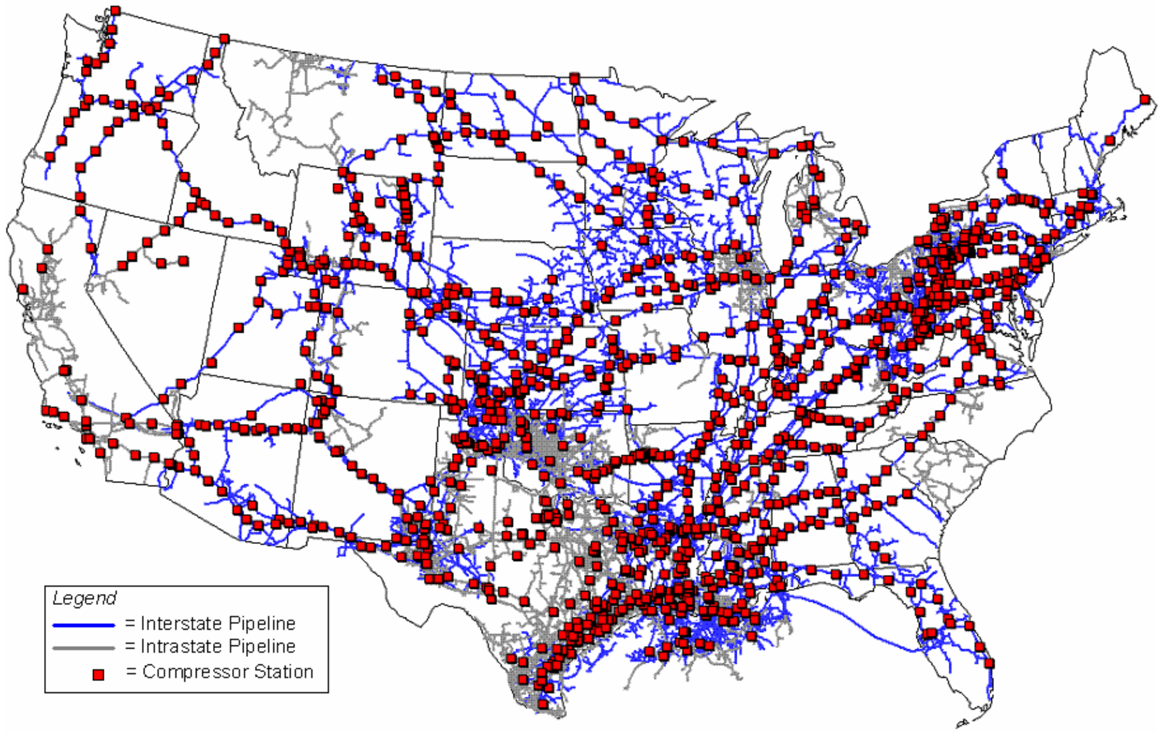
Additional gas storage facilities could potentiality mitigate electricity adequacy concerns due to gas supply or delivery disruptions; however, gas storage facilities are unevenly distributed and typically located remote from gas-fired generators. Nearly all of the gas storage facilities in the U.S. are in 13 states: Texas, Louisiana, Mississippi, Oklahoma, Kansas, eastern New York, eastern Pennsylvania, West Virginia, western Ohio, Illinois, Indiana, eastern Kentucky, and southern Michigan. The western U.S has only about 5% of the nearly 400 active storage facilities.

> *Gas storage is primarily used for two reasons. First, storage is used to take advantage of differences in supply and demand for natural gas. Natural gas production capability is reduced if extraction is cycled across the seasonal swings in gas demand. Therefore, natural gas is largely extracted at a constant rate, and storage is used to balance the annual, and inter-annual, variations in natural gas consumption. This seasonal imbalance between constant supply and seasonal demand produces the seasonal gas price fluctuations which encourage gas to be injected into storage when prices are lower and withdrawn when prices are higher, as well as to supplement gas well withdrawals during peak use periods. Second, storage is used by pipelines as an operational tool to balance pipeline supplies and withdrawals and maintain gas pressure.*[65]

[63] http://www.eia.doe.gov/emeu/northamerica/enginfr2.htm#_VPID_1
[64] Pipelines retain 2-3% of the gas injected for pipeline compressor operation.
[65] http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html

Natural gas is predominately stored at exhausted oil and gas fields, aquifers, or underground salt caverns generally distant from power plants. Since stored gas must still use the pipeline system for delivery, gas storage does not mitigate electricity supply concerns caused by pipeline disruptions. The pipelines and compressor stations are shown below in Figure 19.

Figure 19: Pipelines in the U.S.[66]



From an electricity supply adequacy perspective, a pipeline incident, whether an accidental break or the loss of gas compression, can disrupt the flow of fuel to power plants that are connected to that pipeline resulting in the near simultaneous loss of such power plants as line pack runs out.[67,68] Such an incident could cause switching to alternative fuels, such as distillate fuel oil, which may not be available in the quantities needed for an extended timeframe to replace the lost natural gas, or may be limited by environmental restrictions.

Reliability Considerations - Disruptions of gas flow from wells, as illustrated in the Sable Island incident described below, whether caused by severe weather or equipment failure, are also a potential electricity supply adequacy issue. Since the impact of the loss of gas wells can be the same as the loss of gas pipeline capacity, strategies that address the loss of pipeline capacity can also address the loss of supply from gas wells.

[66] http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/images/compressorMap.gif

[67] In the U.S, pipeline safety is regulated by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).

[68] Recently, a 5+ magnitude earthquake occurred in southern Illinois near the Indiana border. Many state and local government agencies began reviewing earthquake preparedness plans. Gas pipelines may be at risk of rupture due to a severe earthquake.

On Friday, November 30, 2007, a mechanical component failure at the Sable Offshore Energy Project (Sable Island) located off the Nova Scotia coast resulted in a significant loss of natural gas supply injections into the Maritimes & Northeast (M&N)[69] pipeline. By Saturday, December 1, this loss of gas supply finally impacted northern New England gas-fired generating resources. This event resulted in electric capacity deficiencies in the state of Maine. The capacity deficiency in Maine led to a Power Watch declaration of Emergency Operating Procedures (EOPs)[70] and consumers of electricity were requested to reduce electricity use. During this event, both Central Maine Power and ISO-NE coordinated remedial efforts to ensure system reliability. No electric load was shed within the region and electric sector operations eventually returned to normal in two days.

There are differences in the way fuel transportation and transmission services are sold. "Firm" and "non-firm" mean different things in the fuel transportation business when compared to the electric transmission business, and these differences need to be understood and considered. As an example, no market or Balancing Authority would consider a supply as "firm" if its electric Transmission Service is contracted as "non-firm" under a Transmission Provider's tariff. Yet many organized markets and Balancing Authorities would consider a supply as "firm" if it has Firm Transmission Service even though its natural gas fuel delivery is contracted as "non-firm" under a natural gas pipeline's tariff and it has no back-up oil fuel. The reliability aspects of such gas transportation arrangements are more definitive than the distinction implied by "firm" or "non-firm" delivery categories. Several factors could make non-firm gas deliveries acceptable from a reliability perspective. These include:

1. Generation with dual-fuel capability that could switch to an alternate fuel without disrupting its production of power if its non-firm natural gas delivery was curtailed.[71]
2. Generation with multiple non-firm pipeline sources, such that the interruption of natural gas deliveries by one pipeline would not disrupt its power production.

Generators with firm gas transmission capacity may not have the ability to withdraw their maximum hourly demand because of how they contracted for their deliveries. Most pipeline tariffs contract for gas capacity based on the contracted maximum daily energy withdrawals specified by the generator. These same tariffs typically limit the hourly withdrawal rate to 1/24th of the contracted maximum daily energy withdrawals.[72]

There are some contractual refinements that supplement the discussion above. Each plant with a firm transportation nomination is considered a "primary "delivery point. A Generation Owner (GO) who contracts for gas transportation for a number of generators at different locations from the same pipeline may not be able to produce 100% of its capacity based upon the contracted firm pipeline capacity for each plant. In this case, a GO may be relying upon its ability to

[69] http://www.iroquois.com/new-Internet/igts/PipelineSvs/ps_sysmp.asp
[70] ISO-NE implemented up to Action 12 of Operating Procedure No. 4 – Action During a Capacity Deficiency (OP4).
[71] Curtailments of non-firm gas deliveries require one to two hours of notice under most gas pipeline tariffs, allowing a generator to switch fuels in a controlled manner.
[72] A "uniform withdrawal rate" is the typical pipeline tariff terminology that requires that hourly withdrawal rates to not exceed 1/24th (or 4.17%) of the contracted daily deliveries. Other pipelines have more flexible hourly scheduling requirements; some, for example, may allow hourly deliveries to be up to 6% of the contracted daily deliveries.

nominate some of its contracted capacity at other generator locations (i.e., other "primary" delivery points) to the locations of the generators that will be operating. The operating generators that receive such supplemental nominations are "alternate" delivery points.

Pipelines allow customers to switch their total firm gas capacity to different locations, provided that (i) the sum of the customer's primary and alternate delivery nominations do not exceed their total gas capacity under contract *and* (ii) the deliveries to alternate delivery points do not impede the deliveries to the primary delivery points of *any* other pipeline customers. This strategy recognizes the low probability that all generators will be at their simultaneous maximum capacities, as one or more generators may be out of service due to planned or unplanned outages. Therefore, a generation owner may have 90% of the gas needed at a particular location under a firm transportation contract and assume that it could nominate the additional 10% from locations that will not be operating at full capacity. As described above, the nominated 10% capacity to the alternate delivery point is not 100% guaranteed. However, once granted, pipelines will interrupt non-firm transportation if needed to maintain service to alternate delivery points.

Questions have also been raised regarding the potential impacts from compositional variability within natural gas streams by gas-fired generators. Gas interchangeability and/or quality are of greatest concern to large frame combustion turbines because their NO_x combustion systems are particularly sensitive to its composition. Varying fuel characteristics are strongly impacted by the natural gas origin.

Two NERC regions – NPCC[73] and FRCC[74] – have already performed an analysis on natural gas transportation and its potential impact on reliability. In addition, other areas (for example, ISO-NE) continue to monitor the impact of fuel quality on the reliability of combustion turbines. Their analyses can be used as a starting point by others.

[73]For NPCC, see http://www.npcc.org/documents/regStandards/Guide.aspx, B-08 "*Guidelines for Area Review of Resource Adequacy*,"

[74] For FRCC see pages P6:2-32 of https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Handbook%200208.pdf entitled *"FRCC Generating Capacity Shortage Plan."*

Rising Global Demand Impacts for Electric Power Equipment

High growth in global demand for energy, including electricity, has led to increased demand for both transmission and generation electric power equipment Much of the equipment is manufactured overseas and shipped to the U.S. Further, global manufacturing capacity for equipment has not kept pace with demand. Therefore, expected delivery times have recently lengthened considerably, a trend expected to continue through 2017.

Background: Much of the equipment required by the electric utility industry represents specialized orders, and large inventories of such equipment are not maintained by manufacturers. Without equipment standardization, there is little surplus capacity for electric power equipment, and delivery times will always be sensitive to external pressures. Global demand for power equipment is rising significantly, especially in countries whose economies are accelerating. The Table 5 provides a perspective from a sampling of countries experiencing high growth.[75]

Table 5: Global Demand for Power Equipment is Rising.

Country	India 	China 	Brazil 	S. Africa 
Power Supply Situation	Deficit Shortage 11-13%; 43% with power	Adequate but moving towards deficit 10% of annual growth required for future demand	Adequate Net importer of electricity: long term contract to import power from Itaipu hydro station located in Paraguay	Surplus Excess generating capacity; deficit expected in near future
Major Investment Initiatives next 5 years	$100 billion	$75 billion	$40 billion	$15 billion
Types of Investments in Generation	▪ Nuclear ▪ Renewable energy	▪Coal ▪Nuclear sources	▪ Hydroelectric/ thermal ▪ Nuclear resources	▪Nuclear ▪Coal-fired plants
Range of Forecast GDP Growth (2007-2011)	8.3 - 7.6%	9.5 - 7.6%	3.4 - 3.7%	4.9 - 4.6%

[75] TSC Research

The extended expected delivery times for equipment leads to three issues that can impact future reliability:

1. Generation and transmission projects must be planned farther in advance.
2. Lack of flexibility to respond to unexpected or quickly changing conditions.
3. Longer times to replace depleted inventories resulting from catastrophic events.

Meanwhile, there is a significant worldwide focus on renewable resources to provide the growing requirements for electric energy. The demand for renewable energy in the United States exceeds supply. Further exacerbating this situation is the fact that legislation is in place in over twenty-five states that mandates renewable portfolios of up to 30% of renewable energy to be in place over a time period from fifteen years to as short as five years. It is estimated that, absent accelerated construction, the demand for renewable resources could exceed the available supply by more than 30% by 2010. This pressure will particularly strain the ability of the United States to produce wind turbines. Currently, only two manufacturers in the U. S. account for more than three-fourths of the market.

Additional and reinforced transmission infrastructure will be required to connect these renewable resources to load centers. In the U.S. 30% to 50% of the transmission and distribution network is 40-50 years old and may require repair or replacement in the coming years.[76] These factors, along with the transmission infrastructure necessary to meet increased global energy demand, strains manufacturers' ability to supply the needed transmission system equipment, with the net result being longer delivery times.

Reliability Considerations: With the substantial increase in projected wind and nuclear generation, it is vital that the associated equipment be available. For example, there are fifteen applications pending for new nuclear facilities in eight states, almost 145 GW of new wind generation across North America (Proposed), as well as the requisite bulk power transmission additions to reliably integrate these new resources into the bulk power system. The impact of equipment delays on the timely completion of these facilities can significantly impact future bulk power system reliability.

Delayed equipment and depleted inventories can cause near term and event-related shortages of transmission or resources. Over time, these extended delivery times should be factored into the lead times for planned projects as well as equipment inventory strategies. However, many organizations may experience an adjustment period during which there will be some reliability risks. To manage these risks, organizations should:

- Build supply chain reliability;
- Transition to industry specification standards;
- Diversify supply portfolios; and
- Solidify service partnerships and redefine alliance relationships.

[76] http://www.weidmann-acti.com/u/library/2006bartleypaperyes.pdf

Increased Adoption of Distributed Generation and Demand-Side Resources

Distributed generation, demand-side management (demand response and energy efficiency) and new technologies will become critical to meeting increasing demands for electricity in North America.

Background: The potential benefits that demand-side and distributed generation resources bring to bulk power system reliability must be balanced with the operational and forecasting challenges being faced as the penetration of these resources increases.

Demand-side and distributed generation resources can be categorized into a number of sub groupings:

- Distributed generation (DG) is a term used to describe the small scale production of power, typically located close to demand or connected to distribution systems. In certain cases, the plants may often be located "behind the meter" at sites such as hospitals and industrial facilities. DG is also known as on-site generation, dispersed generation or embedded generation. Typical system reliability benefits attributed to DG may include: 1) Reduced energy losses and upstream congestion on transmission lines; 2) Improved local reliability; and 3) Faster permitting than transmission line upgrades.

- Demand-side management (DSM) is often understood to include two components[77]: energy efficiency (EE) and demand response (DR). DSM resources can lead to reductions in supply-side and transmission requirements to meet total internal demand. Planners and Operators have already integrated demand-response programs: 1) Capacity resources; 2) Ancillary Services; and 3) Energy reductions. Long-term reliability benefits include reduced supply-side and transmission requirements as well as augmentation of operational and long-term planning margins. DR is also considered as an effective tool in responding to system events, such as sudden loss of supply, and can be included in UFLS and UVLS schemes. These resources can offset or defer the need for large scale generation investment (i.e. large individual grid-connected generation facilities). EE generally refers to projects which reduce energy use at all times – such as compact fluorescent lighting – but which cannot be controlled at the time of peak.

Reliability Considerations: To realize the potential benefits of DG and DSM outlined above, planners and operators must integrate them reliably into the bulk power system.

Distributed Generation - Increased DG integration must support: 1) Reliability – DG must not degrade the quality and reliability of supply to distribution-connected consumers, 2) Visibility – DG must be visible to the system operators to allow real time decisions for the reliable operation of the grid, and 3) Requirements – Technical requirements for DG must support the reliable operation of the bulk power system.

As the penetration of DR resources grows, the frequency and duration of their dispatch will also grow. If DR performance diminishes in response to a higher frequency and duration of dispatch,

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

electricity supply adequacy could be impacted. Current resource planning methods often fail to fully address the unique characteristics of DR resources.

As more distributed generation is contemplated and deployed, the question begins to arise as to how planners and operators can best utilize these resources for reliability purposes. Several challenges remain that complicate how distributed generation is "counted on" for reliability. First and foremost, unlike with larger generating units, system operators do not typically have the same kind of visibility and control over these distributed assets – especially those connected to the distribution network as opposed to the bulk transmission system.

Additionally, the performance of generation connected to the distribution system currently is not covered by NERC Standards. While the loss of a single unit connected to the distribution system may not materially impact reliability on the rest of the system, the collective loss of many distributed generators – as may occur during a system disturbance – could have a significant impact to reliability in the area. For example, based on the current interconnection standards from the IEEE Power and Energy Society,[78] distributed generation resources may disconnect from the power grid when short-term low voltage events occur either to prevent damage to the equipment or to meet anti-islanding voltage drop-out requirements on the distribution system. Bulk power system reliability requirements, however, may require the units to "ride through" the excursions to support the grid, prevent cascading outages, and aid in restoration. Failure of generation to meet these requirements could lead to system instability and/or voltage collapse, especially if the demand being served by the distributed generation stays connected when the resources drop off-line. In this scenario, distributed generation could, in fact, negatively impact reliability in a region.

Distributed generation can support reactive performance of the bulk power systems due to close proximity of the grid to generators. However, more studies are needed to measure the potential reactive benefits.

Therefore, NERC Standards may be required reconciling potential conflicts between the need to maintain bulk power system reliability and existing IEEE-PES standards for the distribution network. Industry investigation into the potential impacts of distribution connected generation on bulk power system reliability could reveal needs and required NERC Standard activity.

Demand Response and Energy Efficiency - As dispatchable demand response is used as a non-emergency resource more often, the frequency of dispatch will increase. If the performance diminishes in reaction to the higher frequency of dispatch, system reliability could be affected as other resources may not be available in time to provide the ancillary services or energy required. In many cases, dispatchable demand response resources have not yet been tested to meet system reliability requirements at higher dispatch frequencies. To best measure the potential reliability benefits of DR, it is vital to collect event data for Dispatchable, Controllable, Dispatchable Economic DR and Non-Dispatchable DR. Please refer to the *Capacity, Demand and Event Definition* section for further discussion of these categories.

To incorporate EE into resource planning, the energy efficiency peak demand reduction must be defined so resource planners can evaluate it along with capacity resources. Care must be exercised to ensure that the estimates are not misused for other applications. Successful

[78] IEEE 1547, "IEEE Standard on Interconnection Distributed Resources with Electric Power Systems."

integration of energy efficiency into resource planning requires close coordination between those responsible for energy efficiency and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives. A recent NERC report stated[79]: "*For NERC to seriously consider the reliability benefits of EE, the resources promised by energy efficiency programs must be reconciled (measurement/validation) on a historical basis with projections. Once this validation occurs, DSMTF proposes to modify Total Internal Demand with projections.*" To best measure the potential reliability benefits of DR, it is vital to collect event data for Dispatchable, Controllable, Dispatchable Economic DR and Non-Dispatchable DR.

Plug-in hybrid electric vehicles (PHEV), which can act both as load and mobile storage devices (demand and supply), have the potential to become critical reliability resources – theoretically supporting capacity during times of peak usage and drawing charging power from the grid in the evening hours when, for example, more wind generated energy may be available due to wind patterns. This Grid-to-Vehicle (G2V) and Vehicle-to-Grid (V2G) technology may provide a more efficient use of generation capacity. Recent studies identified the impact of PHEV on system capacity requirements and energy use.[80] DR initiatives will support PHEV integration, thereby playing an integral part in the development of future "Smart Grids." The potential reliability benefits of "Smart Grid" technologies on bulk power systems require more study.

[79] http://www.nerc.com/docs/pc/drdtf/NERC_DSMTF_Report_040308.pdf
[80] http://my.epri.com/portal/server.pt?open=512&objID=243&PageID=223132&cached=true&mode=2.

Transmission of the 21st Century

The 21st century brings new challenges to managing the bulk transmission system that affects the entire electric industry. Change in transmission line design, network reinforcements and communications required to accommodate new technologies can have an impact on the reliability of the bulk power system.

Background: The development of new transmission infrastructure and technologies will be critical to North America's energy future. As these resources are developed, vast improvements to the way operators currently manage and operate the system are beginning to emerge, along with new technologies that will allow planners to more fully utilize existing assets and right-of-ways.

New Technologies - Innovative technologies such as Flexible Alternating Current Transmission Systems (FACTS), for example, are making it possible increase the amount of power that can be transferred over existing lines by managing voltage support along the line. In addition, planners are now able to optimize the use of right-of-way corridors by converting existing transmission lines to higher voltages such as 500 kV and 765 kV using conventional as well as compact transmission line and High Surge Impedance Loading (HSIL) designs. Because High Voltage Direct Current (HVdc) lines typically require less right-of-way acquisition than AC lines of similar capacity and with advances in technology, they are also becoming ever more economic for shorter distance power transfers than before. These designs and technologies can minimize the amount of property required to route new facilities.

In addition to these innovations, advancing "Smart Grid"[81] technology for the bulk power system will enable better visualization of the grid, allowing operators to quickly diagnose system events and respond with greater speed, accuracy, and confidence than ever before. For example, Synchro-phasor technology already installed across much of the grid is already beginning to show marked results, allowing disturbances to be analyzed in much greater detail than in the past. This increased information and control has the potential to significantly improve reliability.

Infrastructure Additions - As new, location-constrained resources (such as wind, wave, nuclear, solar, and clean coal with carbon capture and sequestration) are proposed and built, new transmission infrastructure may be needed to bring energy generated by these resources to demand centers. Transmission may also be needed to support variable resources by providing access to requisite system flexibility, such as ancillary services (i.e. spinning reserves, etc.).

Reliability Considerations: For both new bulk power transmission facilities and existing aging transmission equipment for which rejuvenation may be required due to failures, new transmission technologies and designs can improve bulk power system reliability if they are properly integrated. These technologies can (1) increase the transfer capability of existing transmission facilities and (2) improve the operating flexibility of the bulk power system.

The integration of intermittent resources will pose many challenges including transmission access and use of ancillary services. The large scale addition of demand resources will also impact the transmission system.

[81] http://en.wikipedia.org/wiki/Smart_grid

Controllers and facilities such as Flexible AC Transmission System (FACTS) and HVdc that can respond dynamically to system emergencies will require additional training of system operators. In addition, as part of system rejuvenation, new system capabilities can be installed, such as advanced diagnostics and control, to maintain bulk power system reliability. Future coordinated transmission studies can identify potential locations where this 21st century technology can be reliably implemented. Improvements resulting from the deployment of diagnostics, protection and control technologies, including "Smart Grid" equipment, have the potential to measurably improve the reliability of the bulk power system.

"Smart Grid" technology includes not only the application of advanced meter infrastructure (AMI), but also supports advanced asset management addressing bulk power system reliability. Use of diagnostics and communications will provide more information about the status of the grid and its components. Increased information and control generated from the smart grid infrastructure increases grid effectiveness and provides more tools for operators tasked with maintaining bulk power system reliability. Diagnostics can help monitor the condition of a variety of equipment and warn of potential failures *a priori*. Operators can then, with advanced warning, position the bulk power system and schedule maintenance as required.

For example, the use of phasor measurements units (PMUs) on the bulk power system not only provides *a priori* information on the grid for proactive measures, it also supports advanced adaptive relaying vital to power the "smart grid." In addition, studies are under way to determine if phasor measurement could resolve uncertainties surrounding zone 3 relaying through real time analysis of sequence quantities from the phasor vectors.

As new technologies are integrated and the operation of the bulk power system becomes more heavily reliant on communications and cyber technology, the vulnerability of the system to cyber attack and intrusion may increase. New technologies must be designed and deployed with close attention paid to these issues and ongoing testing and security updating must become routine for system and plant operators. System planners should also begin to consider whether potential cyber criteria have a place in contingency planning or models.

Cyber security and critical infrastructure protection are two of the key issues facing the reliability of the bulk power system today. Adequately addressing these challenges will be critical to the industry's success over the coming years.

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.

Background: Direct human uses of water for drinking or sanitation takes priority over utility and other industrial uses. Most Canadian,[82] and northern WECC utilities have significant reliance on hydro power, and fossil-fueled generating plants depend on water in both the U.S.[83] and Canada for cooling the steam in their condensers. Substantial changes in on-peak capacity of generating plants caused by water restrictions will influence electricity supply adequacy. Transmission requirements will significantly change if replacement power sources are remote from traditional sources serving a given region. The strains on transmission are often only revealed through special drought oriented studies of the transmission system.

Fossil plants may need to consider cooling towers instead of once-through cooling water sources. Auxiliary loads for these new cooling towers is often greater than that used for traditional water sources and can reduce overall plant output.

Reliability Considerations: Hydro plants require a minimum head (the difference between the height of the water behind the dam and the height of the turbines) to function. If water flow into a fore bay above the dam is lessened, it may be necessary to pond (limit outflow) water to build up enough head.

In the U.S. most of the attractive hydro generation sites have already been fully developed and site new plants is unlikely because of environmental concerns and restrictions. For existing plants, environmental minimum flow restrictions may require water releases that bypass hydro turbines to maintain river levels below the dam, essentially rendering the hydro plant useless. Hydro site licenses specify the conditions for the operation of the hydro plant and must be strictly adhered to when operating such plants. In Canada, there is a considerable amount of hydro still potentially available for development.[84] Because of the size, cost and negative environmental impacts of large dam projects, however, hydro development has been increasingly focused on small-scale projects (i.e., those with less than 10 MW of generating capacity).

Low levels or flow in rivers, lakes and other bodies of water used for the cooling of plant thermal systems may affect the thermal cycle of electric generating plants using such water bodies. Lower flow can affect cooling in two ways. First, generator output may be limited because of lower water levels at water intakes or intakes being exposed, limiting their effectiveness or even requiring plant shut down. Second, lower water flow can result in higher water temperatures reducing the cooling system's efficiency and possibly violating environmental thermal restrictions. Without sufficient water use and thermal discharge rights, large fossil and nuclear plants are also often hard to site. Many plants in recent years have been forced to move to "dry-

[82] http://www.ec.gc.ca/Water/en/manage/use/e_use.htm
[83] http://water.usgs.gov/watuse/
[84] http://www.nwri.ca/threats2full/ch2-2-e.html

cooling" concepts dependent on heat exchange with the atmosphere and minimal water use in order to obtain site permission.

NERC will continue to monitor water use issues along with the ongoing research & development. NERC has worked with the Department of Energy National Energy Technology Laboratory (NETL)[85] on water use[86](See *U.S. Clean Water Act: Cooling-Water Intake Structure* subsection in this section). In addition, substantial amount of research and development on this topic is being performed by the Electric Power Research Institute (EPRI).[87]

[85] http://www.netl.doe.gov/technologies/coalpower/ewr/water/power-gen.html
[86] http://www.nerc.com/files/NERC_SRA-Retrofit_of_Once-Through_Generation_090908.pdf
[87] http://my.epri.com/portal/server.pt?open=512&objID=240&&PageID=350&mode=2&in_hi_userid=2&cached=true

2009 Scenario Analysis Summary

Background: The LTRA preparation includes data and information on projected summer and winter electricity supply and demand conditions for the coming ten-year period, along with reliability self-assessments prepared by each regional entity. These data, information, and assessments form the basis of the *NERC reference case* presented in the Long-Term Reliability Assessment, for which detailed analysis and discussion follows. The *reference case* incorporates known policy/regulation changes expected to take effect throughout the studied timeframe assuming that a variety of economic growth, weather patterns and system equipment behaviors are as expected, usually based on historic performance trends.

Regional Scenario Analysis Plans for 2009: To commence scenario analysis development, in December 2007 the NERC Planning Committee (PC) identified and prioritized various resource and transmission impact scenarios for regional and NERC-wide evaluation, based on input from its subcommittees. Regions proposed study outlines to be submitted for next year's 2009 Long-Term Reliability Assessment in conjunction with the regions' normal 2009 – 2018 reference case self-assessment and data submittals. Each region was required to examine one of the following two scenarios:

> **Scenario #1: Study accelerated integration of renewable resources:** Around the world, renewable resources have become a significant portion of the generation mix. The available technologies have matured to the point generation owners and system operators can generally meet federal, state and provincial renewable energy mandates, although penetration may be limited by system integration issues, often due to these resources being variable or intermittent in nature. For example, weather patterns of the region/subregion, the variety of renewable sources, the existing generation mix, and the bulk power system transfer capability with neighboring areas all influence the level of penetration that can be achieved. Another consideration is ancillary services and system re-dispatch needed to support reliable operation to support the level of renewables.
>
> For this scenario, the regions will assess accommodating a minimum of an additional 15% of total energy from new renewable resources, above the reference case values, with no more than 5% made up from energy efficiency. The base year for calculating the energy was set as 2008 to provide a common reference value. The addition of renewable resources may be ramped at a rate that can be integrated into the system while sustaining bulk power system reliability until the end of ten year period.
>
> As part of the data submittal, NERC will be looking for narratives and data similar to the LTRA reference data submittal, including:
>
> - Tabulations of potential capacity (gross and derated)
> - Resource adequacy needs (contribution towards capacity margin with or without the additional resources)
> - Renewables/energy efficiency needed to meet the 15% scenario.
> - Impacts on reliability, e.g. new transmission lines, back-up capacity, impact on load, etc., and
> - Fuel outlook, transmission operational issues and reserves (resource adequacy)

Scenario #2: Scenario selected by the region/sub-region for study in 2009: If there is little or no impact of Scenario #1 on a region/subregion, then Scenario #2 will be evaluated. The regions are expected to select a scenario that significantly impacts supply mix, electricity purchases or sales in the studied region. The emerging issues identified in the 2007 LTRA are potential candidates for this alternate scenario analysis. The assessment and detail required in the analysis will be consistent with the framework provided for Scenario #1.

Each region's scenario analysis identifies the impact on reliability and what needs to happen to keep the resulting system reliable. The scenario results, when presented in 2009 will distinguish the key regional challenges arising from the scenario which are different from the *reference case*. Analytical studies which have already been or can be performed before May 2009 will be used to bolster this scenario assessment.

Summary of Regional Scenarios: The outlines submitted to NERC were generally consistent with what was requested. Because of the significant effort expected to be required in 2009 to produce these scenario analyses along with a reference case, the regions will build their scenario analyses on existing studies or studies that are already underway. In most instances, this means examining a single point in time ten years in the future rather than year-by-year analysis. Several regions will be building their scenarios from the Joint Coordination Study Group (JCSG). Outlines of scenario study plans proposed by regions were approved by the PC at their June 2008 meeting.[88]

Table 6 summarizes each region's plans for the 2009 scenario analysis.

Table 6: Regional plans for the 2009 Scenario Analysis

Region	Scenario	Compare to Reference Case	Annual Peak or Point in Time	Peak capacity	Energy Fuel Mix	Miles of Transmission	Operational Challenges
ERCOT	Wind resources for 15% of new energy	Yes	Annual peak to 2018	Yes	Yes	Yes	Yes
FRCC	Renewable resources for 15% of new energy	Yes	Annual Peak to 2018	Yes	Yes	Yes	Yes
SERC	Southeast Generation Fuel Shift	Yes	Point in Time 2019	Yes	No	Yes	Yes
WECC	Renewable resources for 15% of new energy	Will compare capacity mix	Point in Time 2017	Yes	Yes, but can't compare energy to reference case, will compare by fuel	Approximate	Yes
MRO	Joint Coordinated Study Group: Wind resources for at least 15% of new energy	Yes	Point in Time 2018	Yes	Yes	Yes	Yes
NPCC		Yes		Yes	Yes	Yes	Yes
RFC		Yes		Yes	Yes	Yes	Yes
SPP		Yes		Yes	Yes	Yes	Yes

[88] The draft proposals can be found as *Item 5.b Reliability Assessment Subcommittee Report, Appendix I* of the Planning Committee's June 4-5, 2008 Draft Agenda at http://www.nerc.com/docs/pc/Update_2_PC_Agenda_June%204-5-2008.pdf

Reliability Historical Trends

Introduction

Historical trends of reliability are provided for the first time in NERC's 2008 Long-Term Reliability Assessment. Understanding these trends can lead to improved bulk power system reliability. For example, indication of ongoing threats to reliability can stimulate pre-emptive action in future designs towards maintain bulk power system reliability.

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[89].
- 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.[90]

The purpose of this section is to report historic trends in operating reliability and adequacy for the Eastern Interconnection.[91]

Trends in Operating Reliability

Disturbance Event Trends - NERC classifies system events according to five categories with Category 5 being the most severe (See Table 7). Based on data from NERC's Disturbance Analysis database, Figure 20 depicts all Category 2 through 5 system events for 2002-2007.[92] The events caused by factors other than the performance of the transmission system are not included.

Table 7: Bulk Power System Event Classification Scale

Category 1: An event results in any or combination of:
- a. The loss of a bulk power transmission component beyond recognized criteria, e.g. single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
- b. Frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.
- c. Frequency above the High FTL more than 5 minutes.
- d. Partial loss of dc converter station (mono-polar operation)
- e. Inter-area oscillations

Category 2: An event results in any or combination of:
- a. The loss of multiple bulk power transmission components
- b. System separation with no loss of load or generation
- c. Special Protection Scheme or Remedial Action Scheme misoperation
- d. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the ERCOT Interconnection).
- e. The loss of an entire generation station or 5 or more generators
- f. The loss of an entire switching station (all lines, 100 kV or above)
- g. Complete loss of dc converter station

Category 3: An event results in any or combination of:
- a. The loss of generation (2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection).
- b. The loss of load (less than 1,000 MW)
- c. System separation or islanding with loss of load or generation (less than 1,000 MW).
- d. UFLS or UVLS operation.

Category 4: An event results in any or combination of:
- a. System separation or islanding of more than 1,000 MW of load
- b. The loss of load (1,000 to 9,999 MW)

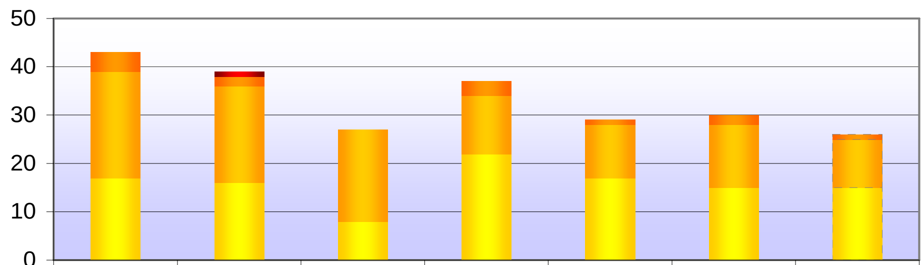
Category 5: An event results in any or combination of:
- a. The occurrence of an uncontrolled or cascading blackout
- b. The loss of load (10,000 MW or more)

[89] Definition of operating reliability http://www.nerc.com/~members/OC_PC/ALR/ as of December 12, 2007
[90] NERC Glossary of Terms ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf
[91] This is the inaugural year for incorporating reliability metrics in the Long-Term Reliability Assessment. Available data for this assessment is solely from the Eastern Interconnection.
[92] See http://www.nerc.com/page.php?cid=5%7C63%7C252 for detailed definitions

Though the performance is mixed, with no discernable trends, a number of observations can be made form this data: 1) While the number of Category 2 events increased in 2005, the number of events in Category 3 has continued a steady decline between 2002 and 2006, 2) Category 4 events were up in 2005 and 2007, after declining in 2004 and 2006.

These data clearly indicate that gaps exist between actual performance and expected system behavior under actual operating conditions. Ultimately the most important measure of operating reliability is that the number of events declines towards zero.

Figure 20: Annual Number of Disturbance Events by Severity



	2002	2003	2004	2005	2006	2007	2008 (Jan-Jul)
Category 5	0	1	0	0	0	0	0
Category 4	4	2	0	3	1	2	1
Category 3	22	20	19	12	11	13	10
Category 2	17	16	8	22	17	15	15

Figure 21 summarizes the contribution of leading causes to the total number of events in 2006. Of the 29 events in 2006, over half were caused by equipment failures, nine by system protection misoperations, and four by personnel errors. Definitions of these cause codes are in Table 8. In addition, the 2008 disturbances have added for comparative purposes.

Table 8: 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

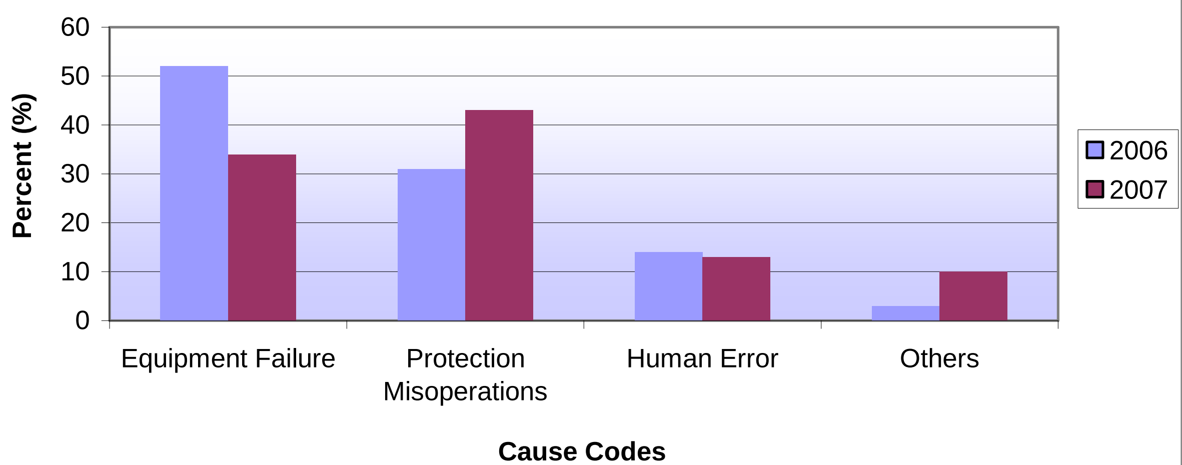
Events caused by relay and/or control initiated operations when not desired or the failure to operate when desired. This category also includes incorrect relay or control settings that do not coordinate with other protective devices.

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.

More work is required to examine the root causes of these events, including the significance of protection system misoperations, the effects of human activities (both by utility workers and the public), as well as the influence of equipment failures on the reliability performance. The objective is to recognize and eliminate unreliable actions and at-risk conditions.[93]

Figure 21: Reported Events by Cause Codes



As is evident in Figure 21, one of the key categories identified as a major cause of system disturbances under analysis has been protection system misoperations. Every major system disturbance since the 1965 Northeast Blackout has been caused or exacerbated by protection system performance ranging from protection system coordination to relay loadability.

NERC's efforts in the Protection System Review Program, launched in 2005 following the 2003 Blackout, have materially reduced relay loadability as a causal or contributory factor in system disturbances; only three loadability instances have occurred since the program was initiated, and only one of those was on the bulk power system

That program's success led to the development a new initiative in 2007 focused on improving more aspects of protection system performance and, thereby, overall system reliability. The initiative continues the work in relay loadability through the development of Standard PRC-023 – Transmission Relay Loadability (awaiting FERC approval), and includes efforts in protection system reliability (redundancy), relay coordination, maintenance, and the coordination of system protection with generator protection and controls.

Analyses of system disturbances over the last year show a trend of generation turbine controls and voltage sensitivity of generator auxiliary systems that caused unexpected loss of generation or runbacks of output. In seven disturbances, the output of 28 generators was lost due to unexpected turbine control action, and an additional 13 generators tripped due to voltage sensitivity. For instance, in the February 2008 south Florida disturbance, after the fault had been

[93] The 2007 event root cause trend is not yet available. A number of 2007 disturbance events are still being analyzed

cleared, an additional 11 generators (1,500 MW) tripped off line due to these problems, further exacerbating the disturbance.[94]

NERC is in the process of expanding the protection system performance initiative to address these issues in conjunction with the IEEE. This enhanced initiative will involve a number of NERC standards projects and increased efforts to raise the profile and priority of protection system performance in the industry

Frequency Excursion Occurrence for the Eastern Interconnection- The ability to maintain load-generation balance within acceptable limits is a key performance indicator to measure real power balancing control performance. 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. Decline in frequency response or degradation of regulation and reserve sharing capability are performance issues worthy of attention, and NERC is currently developing a Standard Authorization Request.[95] For example, for every 0.1 Hz reduction in frequency response, represent 70 MW of reduction in automatic generation control (AGC). Frequency excursions on the grid led to the unexpected loss of over 20 generating units in eight separate disturbances since August 1, 2007.

Figures 22 and 23 present low frequency excursion trends in the Eastern Interconnection indicating significant changes have been taking place during the last six years. From 2002 to 2007, the number of on-peak low frequency events has more than tripled, growing from 186 in 2002 to 675 in 2007; the number of off-peak low frequency events increased from 67 in 2002 to 426 in 2007.

While there is no apparent trend in the longer term (> 2 minute AGC-related) events, the bulk of the excursions identified are short-term step changes in frequency that are an indicator of a decline in primary control (governor response). While these trends do not directly suggest a deterioration of system performance, it is a reliability indicator that bears close monitoring. The NERC Operating Committee's Resources Subcommittee plans to analyze Interconnection real time balancing control performance and identify root cause of out-of-limit operation in 2008.

[94] As a result of this finding, NERC issued an industry advisory to all registered Generation Owners, Generation Operators, Planning Authorities, Planning Coordinators, Transmission Operators, and Reliability Coordinators outlining the issue and urging further coordination. NERC's advisory is available at: http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2008-06-26-01(1).pdf and http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2008-06-26-02.pdf

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

Figure 22– Low Frequency Events

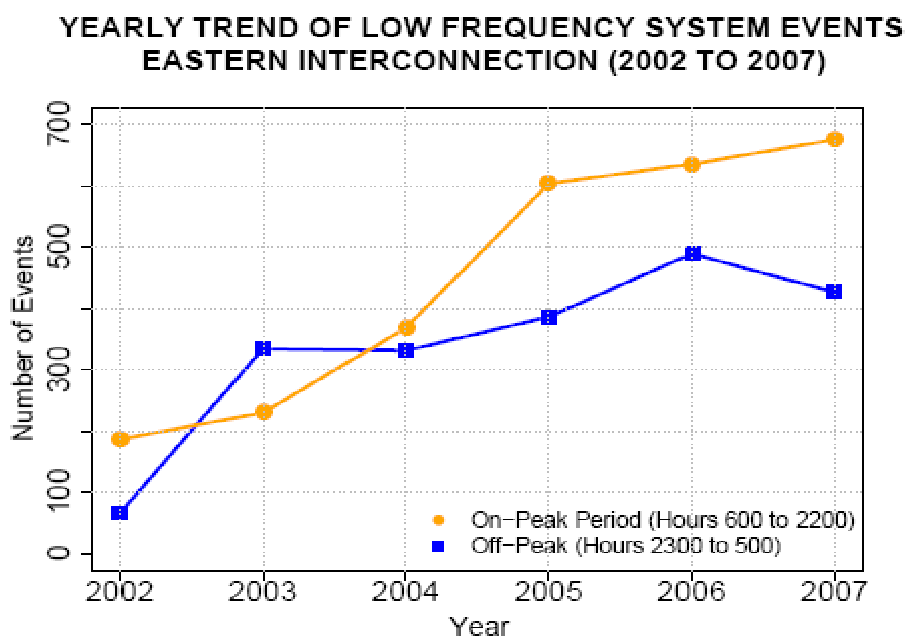
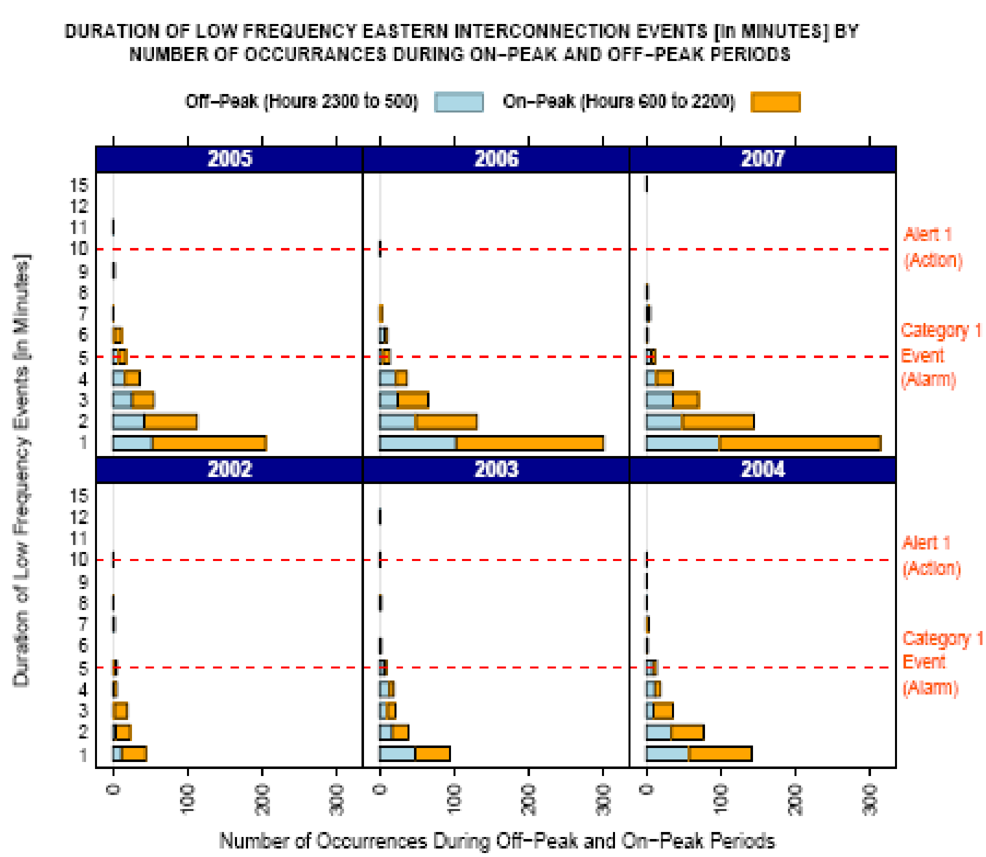


Figure 23 – Low Frequency vs. Duration by Year



The majority of the low frequency events are coincident with Time Error Corrections. Over half of the events occur during Time Error Corrections even though the eastern interconnection is in correction only about 15% of the time. The events also occur just after the primary scheduling periods (06:00 to 22:00).

Figures 24 and 25 present high frequency excursion trends in the Eastern Interconnection. From 2002 to 2007, the number of on-peak high frequency events has increased from 199 to 315; the number of off-peak high frequency events has varied over the years and remained stable through 2006 and 2007. The frequency data from the Western Interconnection did not indicate any significant changes within the last few years.

Figure 24 –High Frequency Events

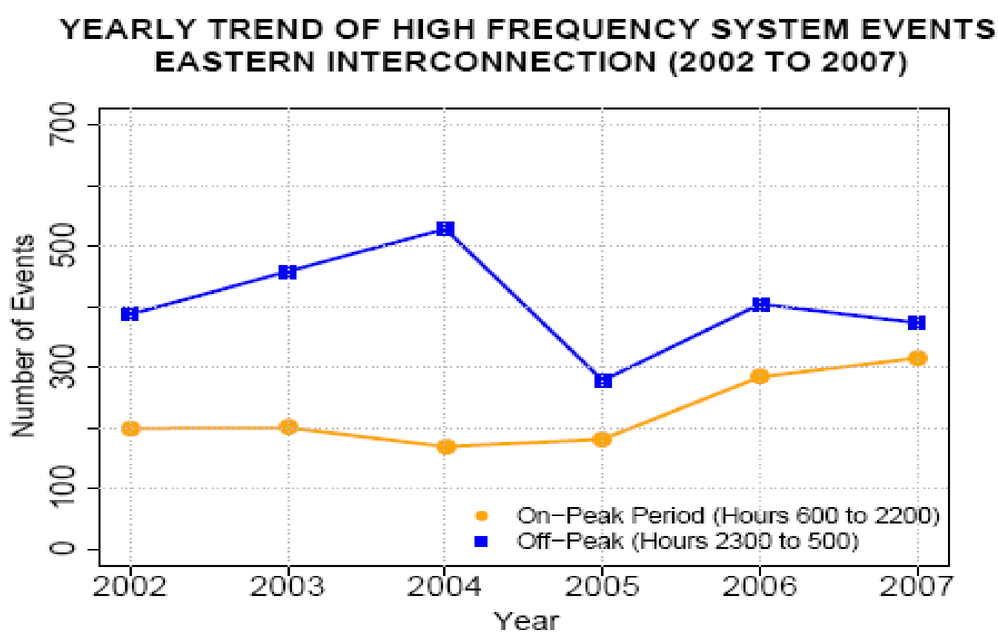
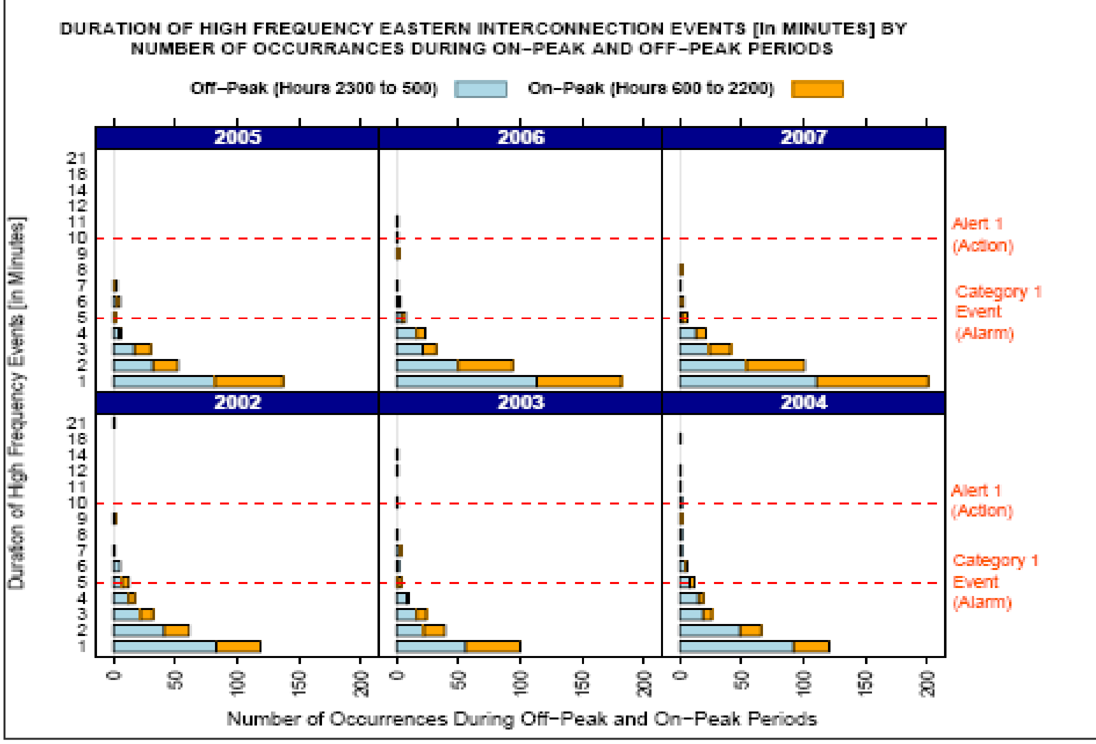


Figure 25 – High Frequency vs. Duration by Year



Improvements to frequency event analysis include analyzing outlier days using statistical process control theory. Generally very noisy days are an indication of something identifiable that is impacting reliability. Significant changes in weekly frequency variation may indicate wide-area or sustained balancing issues. Highly variable frequency often occurs during grid upsets or when operators initiate rapid generation changes to correct congestion. Measuring noise around a target frequency therefore can be a valuable indicator of potential reliability considerations.[96]

Trends in Adequacy

Capacity and Energy Emergency Events - The total number of capacity and energy emergency events between 2002 and 2007 in NERC's Reliability Coordinator Information System (RCIS) database are grouped into three categories (A1, A2 and A3) based on Standard EOP-002-0 (Capacity and Energy Emergencies). Note that Categories A1 and A2 are, in effect, operating procedures used to avoid the interruption of firm customer load[97] as defined in Category A3 (See Tables 9 and 10 along with Figure 26).

Table 9: Categories for Capacity and Emergency Events

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.

a. Public appeals to reduce demand.
b. Voltage reduction.
c. Interruption of non-firm end use loads per contracts.
d. Demand-side management.
e. Utility load conservation measures.

Category A3: Firm load interruption imminent or in progress.

[96] http://www.asq.org/quality-progress/2008/08/statistical-process-control-spc/bright-idea.html

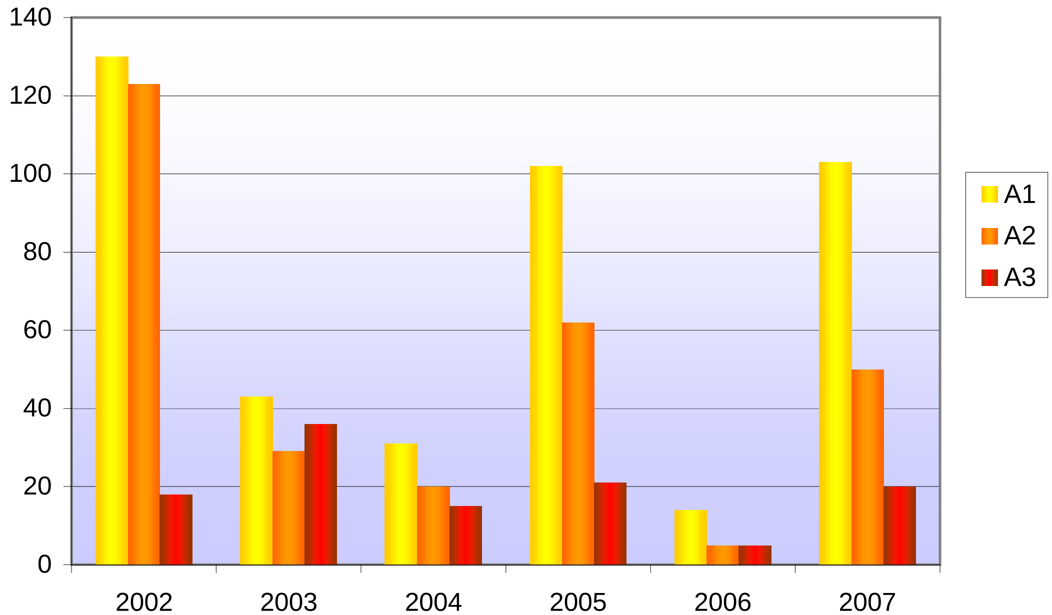
[97] The categories for capacity and emergency events based on Standard EOP-002-0, require revision to specifically account for higher, more regular use of demand response as a capacity resource. For example, the current definitions for Category A2

Table 10 – Capacity and Energy Emergency Event Trend

Categories	2002	2003	2004	2005	2006	2007
A3	18	36	15	21	5	20
A2	123	29	20	62	5	50
A1	130	43	31	102	14	103

The categories for capacity and emergency events based on Standard EOP-002-0, however, require revision to specifically account for higher, more regular use of demand response as a capacity resource. Current definitions for Category A2 include the operation of demand-side resources as a capacity and emergency event, while, in some areas, current industry practice also includes the resource as part of normal, non-emergency operations.

Figure 26: Number of Energy Emergency Alerts by Year (2002-2007)



The 2002 – 2007 quarterly plots are provided in Figure 27. There is a seasonal pattern to the events over the year, with the 2006 summer weather particularly mild compared to other years. A clear periodicity is evident between the summer months in the third quarter (Q3) and winter months represented in the first quarter and fourth quarter (Q1 and Q4) of each year. The monthly annual breakdown of quarters is defined as:

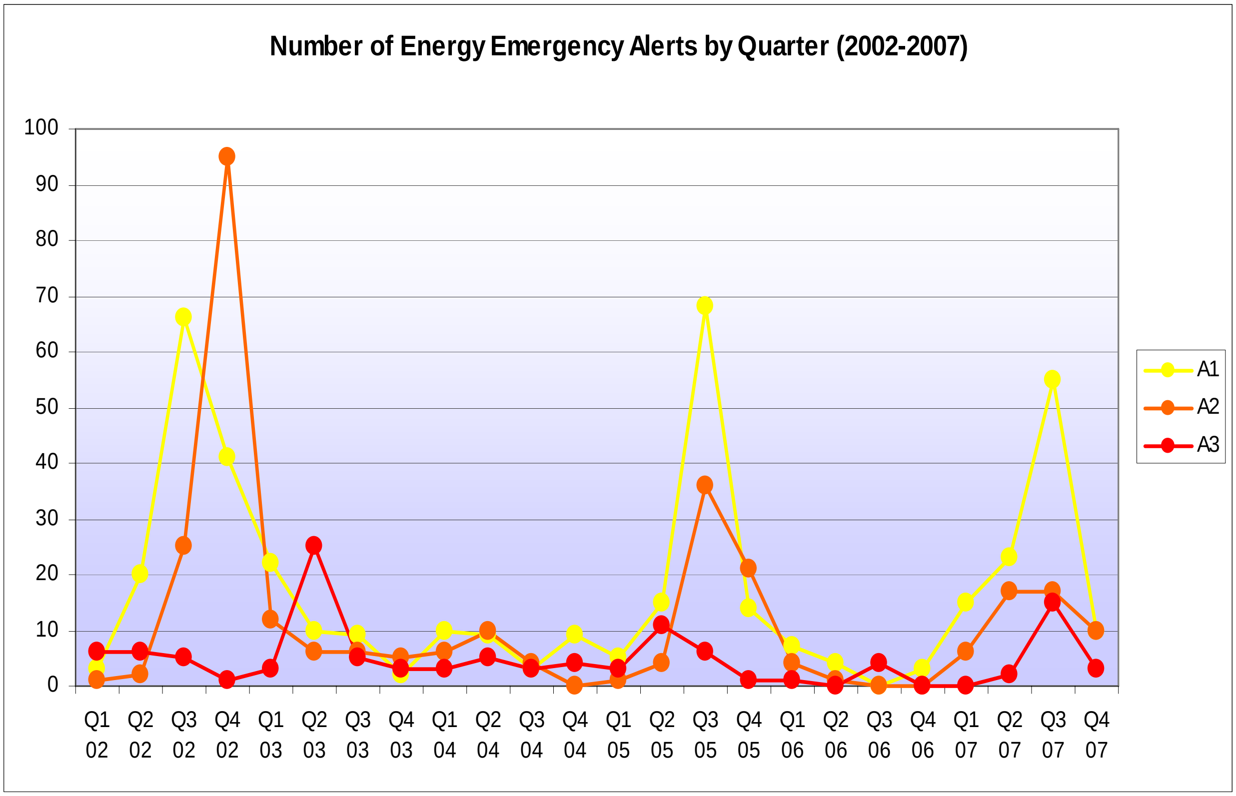
- Q1 – Winter (January, February, March)
- Q2 – Spring (April, May, June)

include the operation of demand-side resources as a capacity and emergency event, while current industry practice includes the resource as part of normal, non-emergency operations.

- Q3 – Summer (July, August, September)
- Q4 – Fall/Early Winter (October, November, December)

Analysis has indicated that extreme weather, short-term load forecast errors and unplanned generation outages are the main causes of the emergency events.

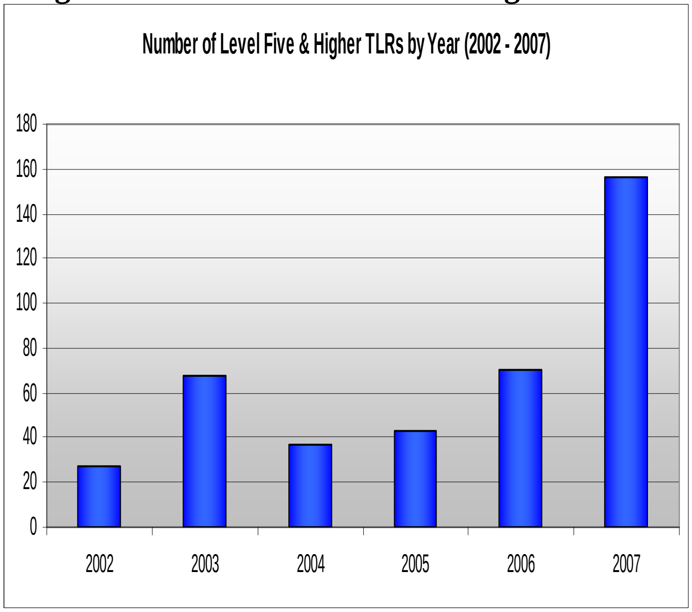
Figure 27 – Quarterly Capacity and Energy Emergency Event Trend



Transmission Loading Relief (TLR) - The TLR[98] process allows reliability coordinators to operate the system within real-time reliability limits while respecting transmission service reservation priorities.[99] Bulk power system customer requests for transactions on Firm Point-to-Point Transmission Service paths that exceed the amount that the system can transfer without violating operating limits is an indication that more transmission may be needed for economic purposes. Reliability Coordinators issue Transmission Loading Relief (TLR) directives in which transaction rights for specific transactions are revoked until system conditions allow their resumption. These TLRs have different levels with Level 6 being the most severe (See Table 11). Trends towards increasing number of TLR Level 5[100] or higher indicate that certain parts of the system are at their limit to supply requested transfers within reliability constraints (see Figure 28).

[98] TLRs are not used in a number of systems where centralized security constrained economic dispatch is employed.
[99] TLR procedure http://www.nerc.com/files/IRO-006-3.pdf
[100] All transactions as prescribed by TLR Level 5b are considered point-to-point across the interface and they can include native load, network service and point-to-point. Hence there is no differentiation and they are comparably treated when it comes to curtailment as stated by FERC pro-forma tariff in Section 13.6 (which starts on sheet no. 47).

Figure 28 – Trends of Level 5 & Higher TLRs



It is necessary to understand the drivers behind congestion to determine if it represents a reliability or economic issue. If congestion is increasing because the transmission system is being fully used to optimize economic dispatch they are not a reliability concern. If congestion is occurring because transfers are needed to serve load, then this variety of congestion is an indicator of reliability concerns. TLR can indicate enforcing the boundaries of economic market activity or they can suggest reliability concerns. TLR below level 5 suggest that non-firm transactions are encountering system limits. While the network limits are rooted in reliability the drivers behind them are economic in nature.

Figure 28 shows that the number of Level 5 and higher TLRs has continued to increase from 2004 to 2007 at a rate more than 15% each year. In 2007 the number of Level 5 TLRs more than doubled over the 2006 figures. The duration of Level 5 TLRs increased from 348 hours in 2006 to 990 hours in 2007.

Table 11: Transmission Loading Relief (TLR) Procedure: *TLR Levels*[101]

TLR Level	Reliability Coordinator Action
1	**Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violations.
2	**Hold** Transfers at present level to prevent SOL or IROL violations.
3a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service.
3b	**Curtail** Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation.
4	**Reconfigure** transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.
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.
5b	**Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation
6	**Emergency Procedures**
0	**TLR Concluded**

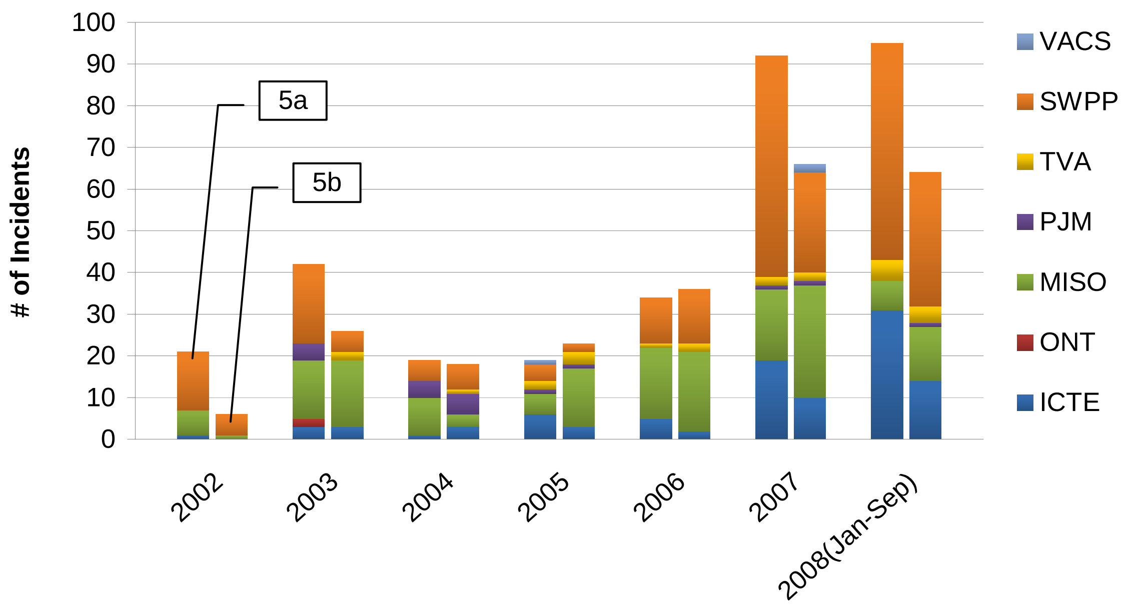
For information about the TLR procedure and transmission service priorities, please refer to NERC reliability standard. Standard IRO-006-3 — Reliability Coordination — Transmission Loading Relief http://www.nerc.com/files/IRO-006-3.pdf

[101] TLR procedures shown apply only to the Eastern Interconnection (http://www.nerc.com/page.php?cid=5%7C67%7C205)

Reliability Coordinators (RCs) also reported forced generation and transmission outages significantly increased in 2007 which may have triggered increased use of Level 5 TLR procedures. To show the progressive use of TLR Level 5, they are further divided into Level 5a and Level 5b.

Figure 29 indicates the number of Level 5 TLRs issued by three RCs (SPP, MISO and ICTE) increased significantly from 2005 to 2007.[102] The higher number of TLR events in the SPP market demonstrates a greater use of the transmission capacity while maintaining reliability (See Table 12). Where other markets may allow re-dispatch without a TLR to maintain reliability of the transmission system, SPP's market protocols require calling a TLR for each congestion situation

Figure 29: Level 5 TLRs for the years 2002- Sep 2008



Note not all regions use TLRs to manage their electricity delivery systems and markets, and their use is neither an absolute nor a broadly applicable indicator of the need for transmission reinforcements.

[102] Note that those RCs not mentioned in the Eastern Interconnection did not issue TLRs during the 2002-2007 timeframe

Application of TLR represent is one method to relieve potential or actual loading. Differences exist on how regions approach congestion management. For example, WECC uses an Unscheduled Flow Mitigation Plan as an equivalent load relief procedure for use in the Western Interconnection[103]. In market structures, redispatch is commonly used as an efficient measure to reduce congestion in transmission systems. MISO[104] and PJM[105] have LMP markets run a security constrained dispatch model which determines the lowest cost generation dispatch without exceeding any transmission limitations, thereby significantly reducing the number of TLRs called. Similarly, ERCOT employs a flow-based/zonal approach to manage forward markets and congestion.[106]

Table 12: SPP's Use of TLRs

Much of the Level 5 TLRs increased in the Southwest Power Pool (SPP), which includes SWPP and ICTE RCs. SPP implemented its Energy Imbalance Market (EIS) on February 1, 2007. Since the implementation of the EIS Market, SPP has experienced an increase in the number of TLR events primarily due to its operating protocols. SPP's market protocols require that the SPP Reliability Coordinator issue a TLR event in accordance with NERC TLR requirements every time congestion is experienced in the market footprint. First, SPP's market protocols require calling a TLR to publicize the fact that SPP is experiencing congestion. Second, it ensures that the other parties contributing to the congestion equitably share in achieving the necessary relief.

Prior to implementation of the market, many constrained flowgates were resolved with generation re-dispatch internal to a Balancing Authority and in many of those instances, TLR was not declared. Now with the EIS Market operational, the same flowgates are reliably managed through TLR and market re-dispatch. Additionally, the structure of the market greatly facilitates more efficient and effective use of the network. Because the market more fully uses transmission capacity, more TLRs are experienced now than under the previous pre-market structure which only allowed bilateral and network transactions to use transmission capacity.

Potential Reliability Metric Enhancements

While TLRs and EEAs were initially developed to help manage/ensure adequacy, they are being used more and more as triggering events for individual entity market decision points. This blurs the lines between reliability tools and market drivers. It also blurs the link between the state of reliability and the use of TLR Level 5 and EEA. Therefore, TLR and the EEA metrics may need improvement for adequacy trends analysis.

Further, the RMWG may also study the correlation between A1/A2, CPS1/CPS2, and balancing area ACE limits (BAAL) with frequency performance and inadvertent interchange performance Frequency is also linked to schedule ramp performance, frequency bias performance, ACE management, and contingency response. Also, Time Error does provide an indication of operational discipline along with inadvertent interchange and Area Interchange Error. The RMWG should evaluate these and other potential metrics to measure operating reliability trends.

[103] This procedure has been accepted by FERC and adopted by NERC Standards http://www.nerc.com/files/IRO-STD-006-0.pdf. WECC USFMP: http://www.wecc.biz/documents/library/UFAS/UFAS_mitigation_plan_rev_2001-clean_8-8-03.pdf

[104] More information on MISO's congestion management procedures can be found in the *2007 STATE OF THE MARKET REPORT FOR THE MIDWEST ISO* at: http://www.midwestiso.org/publish/Document/24743f_11ad9f8f05b_-7b890a48324a/2007%20MISO%20SOM%20Report_Final%20Text.pdf?action=download&_property=Attachment

[105] PJM's congestion management procedures can be found in the *2007 STATE OF THE MARKET REPORT FOR THE PJM INTERCONNECTION* at http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2-sec7.pdf

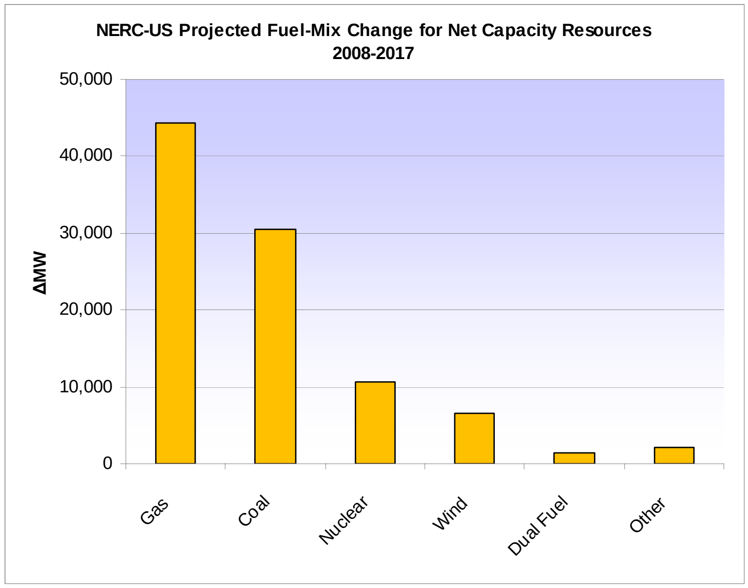
[106] ERCOT's congestion management procedures, entitled *2007 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS* http://www.puc.state.tx.us/wmo/documents/annual_reports/2007annualreport.pdf

Regional Reliability Assessments

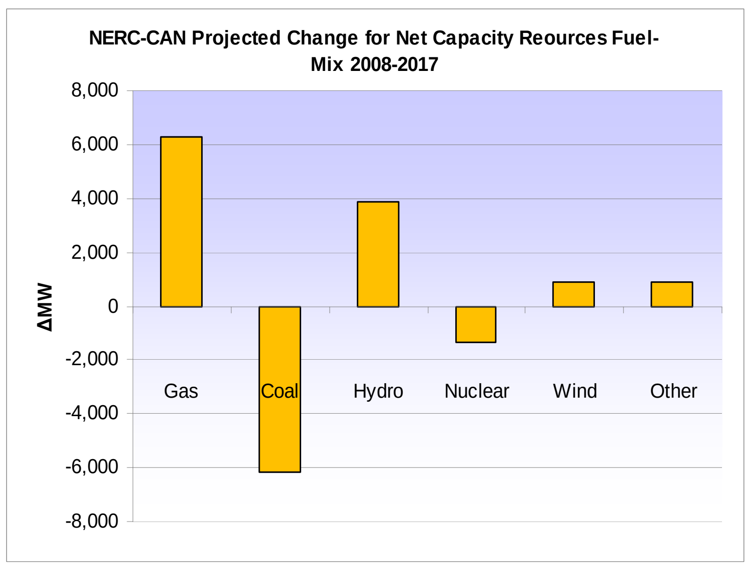
Background

Regional Resource and Demand Projections **-** The figures in the regional self-assessment pages show the regional historical demand, projected demand growth, capacity margin projections, and generation expansion projections reported by the regions for the coming ten-year period.

Capacity Fuel Mix **-** The regional capacity fuel mix charts show each region's relative reliance on specific fuels[107] for its reported generating capacity. The charts for each region in the regional self-assessments are based on the most recent data available in NERC's Electricity Supply and Demand database.



Capacity fuel mix evolution in the U.S. for peak Net Capacity Resources during the 2008-2017 timeframe show increased coal, gas, wind and nuclear plant (See Figure 30).



Nuclear new-build Net Capacity Resources represented in the U.S. 10-year fuel-mix comparison includes 1) FRCC: 2,900 MW,[108] 2) RFC: 5,000 MW,[109] and 3) SERC: 1,200 MW.[110] In addition, a number of new-build nuclear plants have been identified in regional reliability assessments (see *Regional Reliability Assessment* section), though their capacity is not represented in the fuel mix of Net Capacity Resources. Regions considered the following nuclear capacity as part of their Total Potential Resources: 1) SERC: 6,800 MW,[111] and 2) ERCOT: 8,400 MW.[112]

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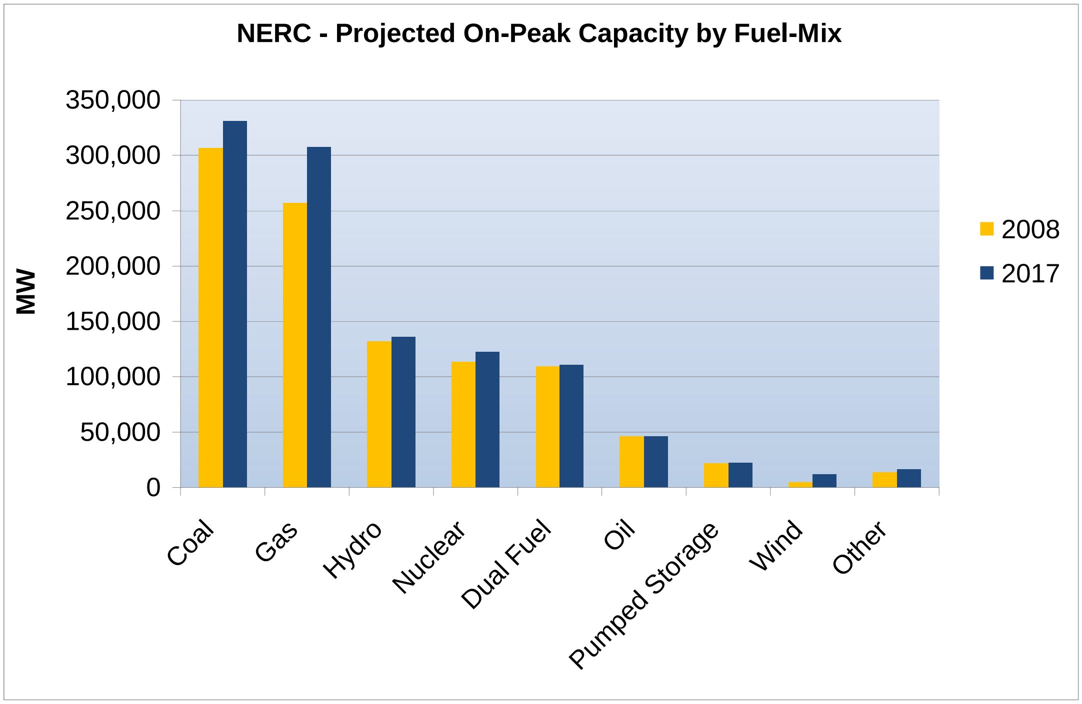
[107] Note: The category "Other" may include capacity for which a fuel type has yet to be determined.
[108] Levy 1 & 2 (1,173 MW each 2016-2017)
[109] 1,600 MW (PPL Corporation, 2013), 1,640 (Constellation Energy, 2015) and 1,563 MW (DTE Energy, 2017)
[110] 1,182 MW (Central in 2012)
[111] 3,102 MW (Delta in 2015), 1,650 MW (Gateway, 2017), 1,100 MW (Southeastern, 2017) & 1,100 MW (VACAR, 2016)
[112] Comanche Peak 3 & 4 at 3,200 MW, STP 3 & 4 at 2,700 MW & Victoria City Nuclear at 3,200 MW

Canada shows a substantial drop in coal-fired and nuclear resources (see Figure 31). Ontario expects to retire 6,400 MW of coal-fired resources across four facilities and 15 units by 2014, fulfilling the commitments called for in the Ontario Power Authority's Integrated Power Supply Plan.[113] In addition, the Ontario sub-region forecasts nuclear reductions resulting from of the removal of one unit in 2015 (797 MW) and two units in 2016 (1,364 MW total). Decisions have not been made at this time about refurbishment or replacement of these nuclear units. Increases in Canada of Net Capacity Resources from gas, hydro and wind plant round off the remainder of the fuel mix during the ten-year assessment.

The NERC-wide fuel mix is found in Figure 32.



Regional Demand & Resource Projections 2008-2017

Resources and Fuel Mix- To improve consistency and increase the granularity and transparency of how regional resource projections are represented in NERC assessment reports, NERC's Planning Committee approved new categories for capacity resources and capacity purchases and sales. The previously-used categories of "committed" and "uncommitted" resource designations used in the *2007 Long-Term Reliability Assessment* were replaced with enhanced categories: 1) Existing; 2) Planned; 3) Proposed Capacity; and 4) Capacity Purchases & Sales.[114]

To better understand the resource acquisition strategy and the relative resource certainty, a layered resource graph, deploying the more detailed resource categorization, can show the risk profile for future resources to meet capacity margins. These graphs can be used to trend capacity margins for comparative assessment against reference margin levels to identify areas where and when additional resources may be required.

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[113] http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=320
[114] See the *Capacity, Demand & Event Definitions* section for detailed definitions.

Figure 33 shows the NERC-wide 2008-2017 summer peak demand capacity margins. The NERC Reference Margin Level capacity margin level of 13 percent is used to identify approximately when additional resources may be needed. While the overall NERC-wide capacity margins appear adequate for most resource scenarios, the results for individual regions/subregions vary widely, discussed in the regional self-assessment sections.

Figure 33: NERC Summer Capacity Margin 2008-2017 Comparison

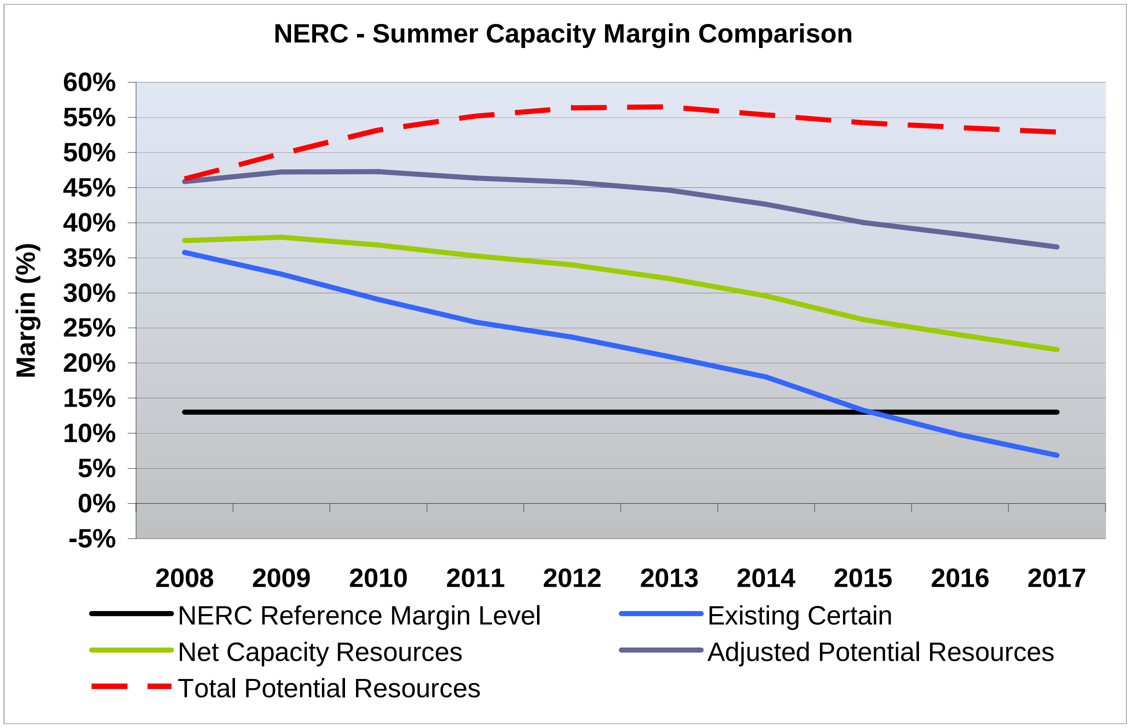


Figure 33 shows NERC-wide the existing capacity sufficiently meets the NERC Target Margin Level through 2015. However, this includes the combination of a predominately summer peaking system (NERC-US) and one that, with the exclusion of Ontario, is a winter peaking system (NERC-Canada). Figures 35 and 35 shown below show NERC-US and NERC-Canada for their respective peaking season. The NERC Reference Margin Level is different for the U.S. (13%) a predominately thermal system, and Canada (9%), a predominately hydro system. [115]

[115] Each region/subregion may have their own specific margin level based on load, generation, and transmission characteristics or regulatory requirements. No NERC-wide minimum margin standard or criteria exits. If provided in the data submittals, the regional/subregional Target Capacity Margin level is reflected as the NERC Reference Margin Level. If not, NERC assigned a 13 percent capacity margin for predominately thermal systems and for predominately hydro systems, 9 percent.

Figure 34: NERC-US Summer Capacity Margin 2008-2017 Comparison

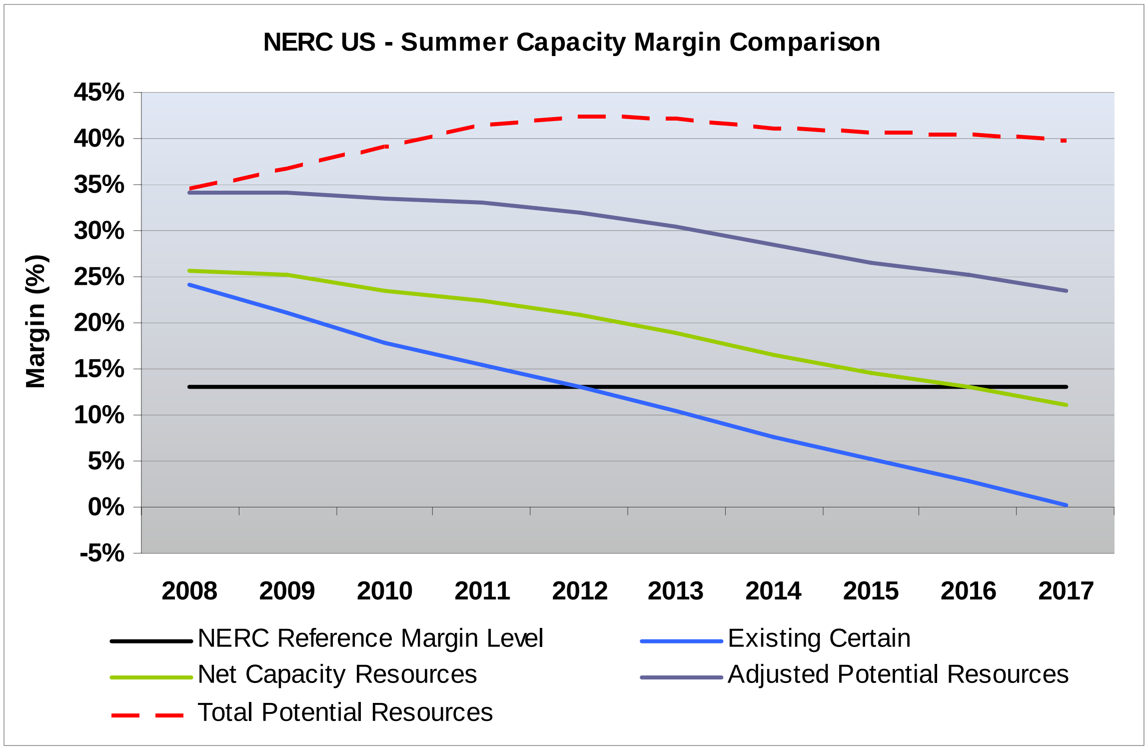
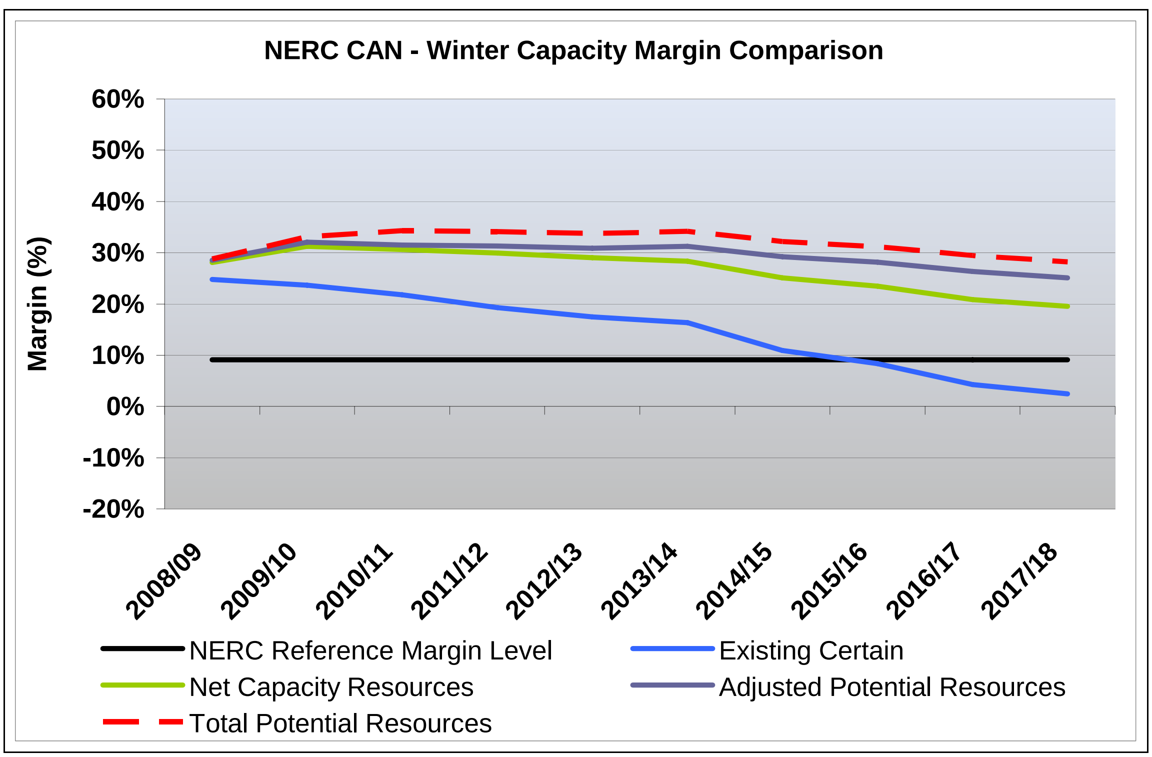


Figure 35: NERC Canada Winter Capacity Margin 2008-2017 Comparison



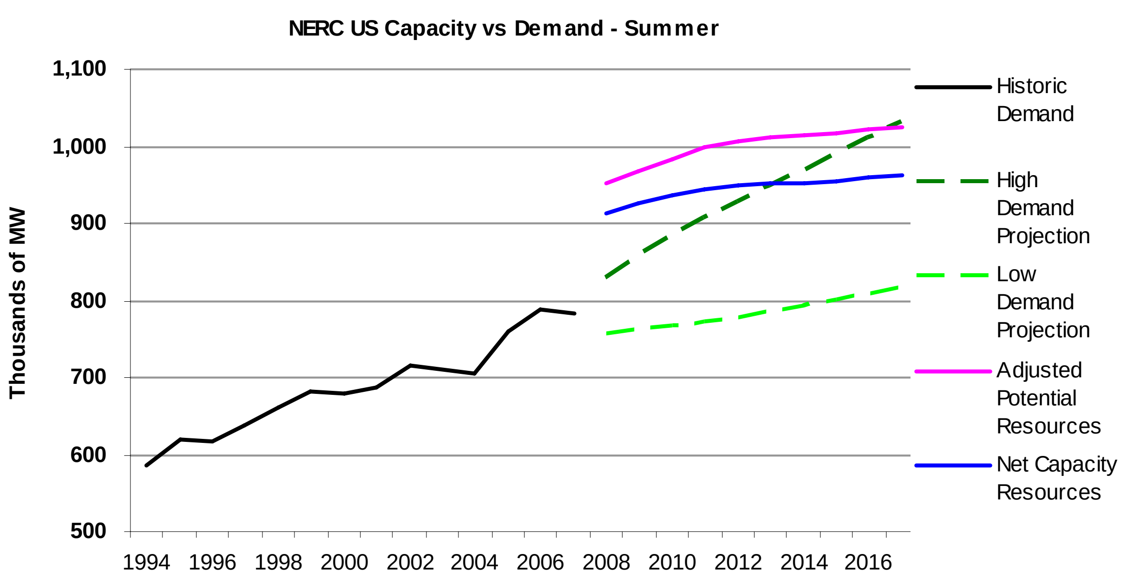
Demand **-** The peak demand projections shown in this report's tables and charts represent an aggregate of weather-normalized projections reported by the regions. In some cases, these regional aggregations do not take into account the regional diversity among the various regional participants' peak demands, which, depending on the geographical size, could significantly influence the capacity margin comparisons. However, in other cases, as regions can be wide-spread, resources would not be deliverable, and sub-regional analysis is more meaningful.

The NERC Load Forecasting Working Group (LFWG) develops bandwidths around the aggregate U.S. and Canadian demand projections to account for uncertainties inherent in demand forecasting (see the *Capacity, Demand & Event Definitions* section)[116].

For the high demand projection, NERC-wide capacity margin appears adequate through the study timeframe when considering Adjusted Potential Resources. However, Net Capacity Resources fall short for this high demand forecast in 2013 when considering Net Capacity Resources.

The Total Internal Demand[117] growth equates to a ten-year average annual peak demand growth in the U.S. for 2008–2017 (See Figure 36) of 1.7 percent in the summer and 1.7 percent in the winter, representing a 0.2% increase compared to last year's report.

Figure 36: NERC US Capacity vs. Total Internal Demand – Summer Peak

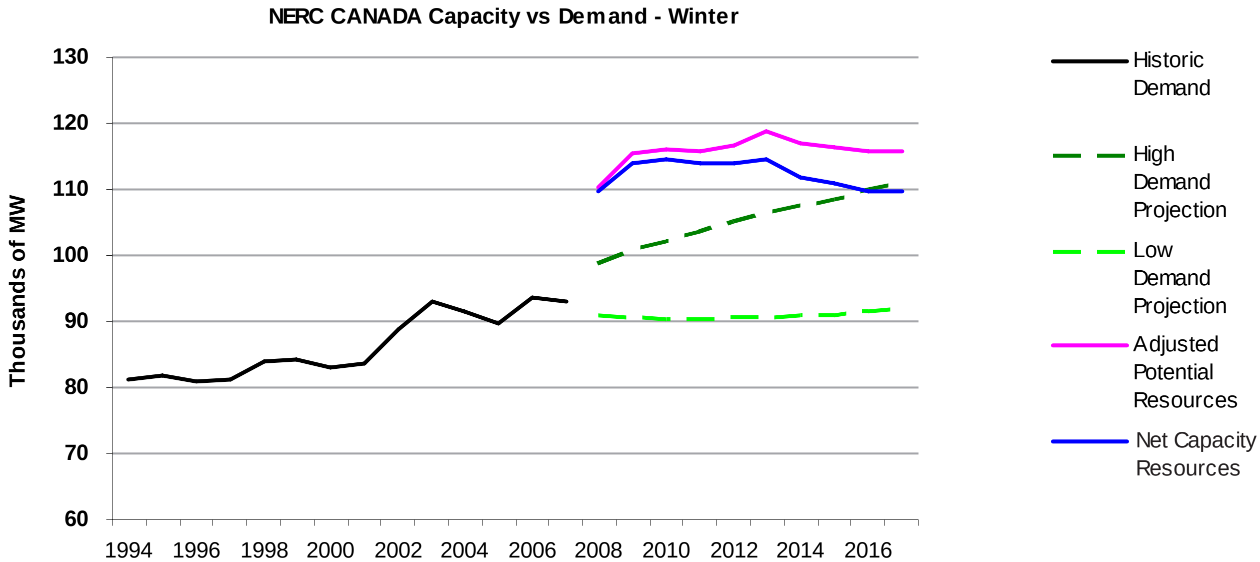


In Canada, the ten-year average annual peak demand growth is 0.8 percent in the summer and 0.9 percent in the winter or 0.1% higher than last year's report (see Figure 37). The average annual growth in the "high" and "low" band U.S. summer peak demands are 2.8 percent and 0.4 percent, and in Canada winter peak demand bands are 1.8 percent and -0.1 percent, respectively.

[116] For the full report, see http://www.nerc.com/docs/pc/lfwg/NERC_2008-2017_Regional_Bandwidths.pdf
[117] Note that Total Internal Demand includes the affect of energy efficiency, but does not include demand response, the impacts of both are included in Net Internal Demand

For the high demand projections, Canada appears adequate for either the Adjusted Potential or Net Capacity Resources.

Figure 37: NERC-Canada Capacity vs. Total Internal Demand – Winter Peak



Tables 13a through 13f are the estimated Resources, Demands and Margins representing a subset of the data submitted to NERC. Key years of 2008 summer, 2008/2009 Winter, 2012 summer, 2012/2013 Winter and 2017 summer and 2017/2018 winter for peak conditions are provided. Year-to-year actual demand growth rates can vary due to variations in economic conditions and weather. Also, actual demands are not corrected for weather or other conditions that deviate from the forecast assumptions.

Table 13a: Estimated 2008 Summer Margins (%), Resources and Demands (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	63,725	71,639	72,503	72,503	72,503	11.0%	12.1%	12.1%	12.1%	11.1%
FRCC	44,417	53,077	53,552	53,553	53,552	16.3%	17.1%	17.1%	17.1%	13.0%
MRO	41,260	46,363	47,875	48,083	48,378	11.0%	13.8%	14.2%	14.7%	13.0%
NPCC	58,371	69,740	72,105	72,105	72,275	16.3%	19.0%	19.0%	19.2%	
New England	26,150	30,950	31,131	31,131	31,301	15.5%	16.0%	16.0%	16.5%	13.0%
New York	32,221	38,790	40,974	40,974	40,974	16.9%	21.4%	21.4%	21.4%	13.0%
RFC	177,200	213,787	213,787	213,806	213,806	17.1%	17.1%	17.1%	17.1%	
RFC-MISO	61,200	70,076	70,076	70,095	70,095	12.7%	12.7%	12.7%	12.7%	12.8%
RFC-PJM	119,700	141,542	141,542	141,542	141,542	15.4%	15.4%	15.4%	15.4%	12.8%
SERC	198,522	235,136	235,485	263,476	264,659	15.6%	15.7%	24.7%	25.0%	
Central	42,163	49,725	49,725	54,332	55,515	15.2%	15.2%	22.4%	24.1%	13.0%
Delta	27,936	30,012	30,012	41,616	41,616	6.9%	6.9%	32.9%	32.9%	13.0%
Gateway	19,105	23,711	23,711	27,751	27,751	19.4%	19.4%	31.2%	31.2%	13.0%
Southeastern	48,215	57,466	57,466	63,266	63,266	16.1%	16.1%	23.8%	23.8%	13.0%
VACAR	61,103	74,222	74,571	76,511	76,511	17.7%	18.1%	20.1%	20.1%	13.0%
SPP	43,056	48,993	50,109	58,514	58,514	12.1%	14.1%	26.4%	26.4%	13.0%
WECC	137,925	166,508	169,876	169,880	171,184	17.2%	18.8%	18.8%	19.4%	12.1%
AZ-NM-SNV	30,996	35,135	36,903	36,907	36,907	11.8%	16.0%	16.0%	16.0%	11.7%
CA-MX US	57,507	64,847	69,714	69,714	71,438	11.3%	17.5%	17.5%	19.5%	13.3%
NWPP	37,778	53,376	50,505	50,505	50,518	29.2%	25.2%	25.2%	25.2%	11.9%
RMPA	12,043	13,302	13,702	13,702	13,702	9.5%	12.1%	12.1%	12.1%	10.5%
Total - US	**764,476**	**905,243**	**915,292**	**951,920**	**954,872**	**15.6%**	**16.5%**	**19.7%**	**19.9%**	**13.0%**
Canada										
MRO	5,886	7,594	7,600	7,600	7,600	22.5%	22.6%	22.6%	22.6%	13.0%
NPCC	48,706	65,118	65,417	65,406	65,406	25.2%	25.5%	25.5%	25.5%	
Maritimes	3,137	5,827	5,827	5,816	5,816	46.2%	46.2%	46.1%	46.1%	13.0%
Ontario	24,351	28,194	28,493	28,493	28,493	13.6%	14.5%	14.5%	14.5%	14.5%
Quebec	21,218	31,097	31,097	31,097	31,097	31.8%	31.8%	31.8%	31.8%	9.1%
WECC	17,907	21,687	21,995	21,995	21,995	17.4%	18.6%	18.6%	18.6%	10.2%
Total - CAN	**72,499**	**94,399**	**95,012**	**95,001**	**95,001**	**23.2%**	**23.7%**	**23.7%**	**23.7%**	**13.0%**
Mexico										
WECC CA-MX Mex	2,223	2,789	2,540	2,540	2,540	20.3%	12.5%	12.5%	12.5%	12.5%
Total - NERC	**839,198**	**1,002,431**	**1,012,844**	**1,049,461**	**1,052,413**	**16.3%**	**17.1%**	**20.0%**	**20.3%**	**13.0%**

* *MISO and PJM information does not sum to the RFC total due to the handling of OVEC data. RFC information is only for demand and capacity within its region.*

Table 13b: Estimated 2008/09 Winter Margins (%), Resources and Demands (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	46,068	74,640	75,504	75,508	75,508	38.3%	39.0%	39.0%	39.0%	11.1%
FRCC	46,093	56,818	57,510	57,510	57,510	18.9%	19.9%	19.9%	19.9%	13.0%
MRO	34,358	43,400	44,987	45,702	46,034	20.8%	23.6%	24.8%	25.4%	13.0%
NPCC	46,185	74,920	75,772	75,772	76,644	38.4%	39.0%	39.0%	39.7%	
New England	20,892	33,678	34,009	34,009	34,881	38.0%	38.6%	38.6%	40.1%	13.0%
New York	25,293	41,242	41,763	41,763	41,763	38.7%	39.4%	39.4%	39.4%	13.0%
RFC	141,200	212,123	212,257	216,200	217,784	33.4%	33.5%	34.7%	35.2%	
RFC-MISO	47,700	67,307	67,307	70,769	70,845	29.1%	29.1%	32.6%	32.7%	12.8%
RFC-PJM	96,400	142,561	142,695	143,093	144,684	32.4%	32.4%	32.6%	33.4%	12.8%
SERC	176,766	228,615	229,627	257,619	258,987	22.7%	23.0%	31.4%	31.7%	
Central	41,908	46,452	46,454	51,061	52,429	9.8%	9.8%	17.9%	20.1%	13.0%
Delta	24,140	23,877	23,918	35,522	35,522	-1.1%	-0.9%	32.0%	32.0%	13.0%
Gateway	14,912	23,631	23,631	27,671	27,671	36.9%	36.9%	46.1%	46.1%	13.0%
Southeastern	40,506	59,335	59,335	65,135	65,135	31.7%	31.7%	37.8%	37.8%	13.0%
VACAR	55,299	75,321	76,290	78,230	78,230	26.6%	27.5%	29.3%	29.3%	13.0%
SPP	31,455	49,107	50,223	59,218	59,218	35.9%	37.4%	46.9%	46.9%	13.0%
WECC	113,504	164,787	167,770	167,822	168,458	31.1%	32.3%	32.4%	32.6%	12.1%
AZ-NM-SNV	19,468	34,687	37,973	38,025	38,025	43.9%	48.7%	48.8%	48.8%	11.7%
CA-MX US	42,929	62,175	60,387	60,387	60,990	31.0%	28.9%	28.9%	29.6%	13.3%
NWPP	41,205	54,620	55,857	55,857	55,921	24.6%	26.2%	26.2%	26.3%	11.9%
RMPA	10,398	13,335	13,377	13,377	13,377	22.0%	22.3%	22.3%	22.3%	10.5%
Total - US	**635,629**	**904,410**	**913,650**	**955,351**	**960,143**	**29.7%**	**30.4%**	**33.5%**	**33.8%**	**13.0%**
Canada										
MRO	7,316	9,074	9,091	9,091	9,091	19.4%	19.5%	19.5%	19.5%	13.0%
NPCC	63,170	74,410	76,036	76,593	76,593	15.1%	16.9%	17.5%	17.5%	
Maritimes	5,220	6,314	6,353	6,342	6,342	17.3%	17.8%	17.7%	17.7%	13.0%
Ontario	22,900	27,993	29,398	29,966	29,966	18.2%	22.1%	23.6%	23.6%	14.5%
Quebec	35,049	40,103	40,285	40,285	40,285	12.6%	13.0%	13.0%	13.0%	9.1%
WECC	21,664	23,247	24,532	24,532	24,732	6.8%	11.7%	11.7%	12.4%	10.2%
Total - CAN	**92,150**	**106,731**	**109,659**	**110,216**	**110,416**	**13.7%**	**16.0%**	**16.4%**	**16.5%**	**13.0%**
Mexico										
WECC CA-MX Mex	1,641	1,951	2,358	2,358	2,358	15.9%	30.4%	30.4%	30.4%	12.5%
Total - NERC	**729,420**	**1,013,092**	**1,025,667**	**1,067,925**	**1,072,917**	**28.0%**	**28.9%**	**31.7%**	**32.0%**	**13.0%**

* *MISO and PJM information does not sum to the RFC total due to the handling of OVEC data. RFC information is only for demand and capacity within its region.*

Table 13c: Estimated 2012 Summer Margins (%), Resources and Demands (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	68,833	72,486	78,843	86,397	116,615	5.0%	12.7%	20.3%	41.0%	11.1%
FRCC	48,212	52,817	59,979	59,979	59,979	8.7%	19.6%	19.6%	19.6%	13.0%
MRO	44,993	45,221	49,529	54,029	61,324	0.5%	9.2%	16.7%	26.6%	13.0%
NPCC	61,065	69,585	72,923	72,923	84,901	12.2%	16.3%	16.3%	28.1%	
New England	27,541	31,246	31,673	31,673	43,651	11.9%	13.0%	13.0%	36.9%	13.0%
New York	33,524	38,339	41,250	41,250	41,250	12.6%	18.7%	18.7%	18.7%	13.0%
RFC	188,900	213,787	219,492	227,911	255,072	11.6%	13.9%	17.1%	25.9%	
RFC-MISO	65,200	70,076	72,540	74,493	77,322	7.0%	10.1%	12.5%	15.7%	12.8%
RFC-PJM	127,600	141,542	144,783	150,943	175,581	9.9%	11.9%	15.5%	27.3%	12.8%
SERC	214,834	233,581	240,273	268,712	276,703	8.0%	10.6%	20.1%	22.4%	
Central	44,732	48,848	50,304	54,774	56,778	8.4%	11.1%	18.3%	21.2%	13.0%
Delta	30,352	29,655	29,655	41,259	43,391	-2.4%	-2.4%	26.4%	30.1%	13.0%
Gateway	20,000	23,787	24,332	28,839	28,839	15.9%	17.8%	30.6%	30.6%	13.0%
Southeastern	53,896	57,736	59,418	65,218	67,833	6.7%	9.3%	17.4%	20.5%	13.0%
VACAR	65,854	73,556	76,565	78,622	79,862	10.5%	14.0%	16.2%	17.5%	13.0%
SPP	46,248	48,628	54,328	62,975	67,981	4.9%	14.9%	26.6%	32.0%	13.0%
WECC	149,137	166,578	175,431	175,435	184,342	10.5%	15.0%	15.0%	19.1%	12.1%
AZ-NM-SNV	34,802	35,026	37,087	37,091	38,399	0.6%	6.2%	6.2%	9.4%	11.7%
CA-MX US	60,731	64,899	72,021	72,021	77,521	6.4%	15.7%	15.7%	21.7%	13.3%
NWPP	41,004	53,809	52,123	52,123	54,472	23.8%	21.3%	21.3%	24.7%	11.9%
RMPA	13,047	12,852	14,744	14,744	14,744	-1.5%	11.5%	11.5%	11.5%	10.5%
Total - US	**822,222**	**902,683**	**950,798**	**1,008,361**	**1,106,917**	**8.9%**	**13.5%**	**18.5%**	**25.7%**	**13.0%**
Canada										
MRO	6,394	7,613	8,048	8,048	8,048	16.0%	20.6%	20.6%	20.6%	13.0%
NPCC	49,143	62,761	69,586	71,976	72,444	21.7%	29.4%	31.7%	32.2%	
Maritimes	3,289	6,526	6,526	6,580	6,723	49.6%	49.6%	50.0%	51.1%	13.0%
Ontario	23,788	24,504	30,473	32,809	33,135	2.9%	21.9%	27.5%	28.2%	14.5%
Quebec	22,065	31,731	32,587	32,587	32,587	30.5%	32.3%	32.3%	32.3%	9.1%
WECC	19,984	21,889	22,912	22,912	25,196	8.7%	12.8%	12.8%	20.7%	10.2%
Total - CAN	**75,521**	**92,263**	**100,546**	**102,936**	**105,688**	**18.1%**	**24.9%**	**26.6%**	**28.5%**	**13.0%**
Mexico										
WECC CA-MX Mex	2,769	2,356	2,722	2,722	3,233	-17.5%	-1.7%	-1.7%	14.4%	12.5%
Total - NERC	**900,512**	**997,302**	**1,054,066**	**1,114,019**	**1,215,838**	**9.7%**	**14.6%**	**19.2%**	**25.9%**	**13.0%**

* *MISO and PJM information does not sum to the RFC total due to the handling of OVEC data. RFC information is only for demand and capacity within its region.*

Table 13d: Estimated 2012/13 Winter Margins (%), Resources and Demands (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	49,371	75,015	81,372	88,926	119,144	34.2%	39.3%	44.5%	58.6%	11.1%
FRCC	50,104	56,458	65,107	65,107	65,107	11.3%	23.0%	23.0%	23.0%	13.0%
MRO	37,436	43,030	47,292	52,426	59,984	13.0%	20.8%	28.6%	37.6%	13.0%
NPCC	48,258	72,041	73,759	73,759	86,424	33.0%	34.6%	34.6%	44.2%	
New England	21,786	31,246	31,673	31,673	44,331	30.3%	31.2%	31.2%	50.9%	13.0%
New York	26,472	40,795	42,086	42,086	42,092	35.1%	37.1%	37.1%	37.1%	13.0%
RFC	149,100	212,123	217,827	229,321	257,729	29.7%	31.6%	35.0%	42.1%	
RFC-MISO	51,000	67,307	69,771	74,471	77,300	24.2%	26.9%	31.5%	34.0%	12.8%
RFC-PJM	101,200	142,561	145,801	152,276	178,174	29.0%	30.6%	33.5%	43.2%	12.8%
SERC	188,972	227,231	235,730	264,120	273,164	16.8%	19.8%	28.5%	30.8%	
Central	42,995	46,197	48,881	53,355	55,632	6.9%	12.0%	19.4%	22.7%	13.0%
Delta	25,752	23,725	24,102	35,706	37,856	-8.5%	-6.8%	27.9%	32.0%	13.0%
Gateway	15,897	23,778	24,525	28,675	28,675	33.1%	35.2%	44.6%	44.6%	13.0%
Southeastern	45,086	58,803	60,485	66,285	68,934	23.3%	25.5%	32.0%	34.6%	13.0%
VACAR	59,241	74,729	77,738	80,099	82,067	20.7%	23.8%	26.0%	27.8%	13.0%
SPP	34,021	48,754	53,730	62,916	64,388	30.2%	36.7%	45.9%	47.2%	13.0%
WECC	121,657	165,001	171,862	171,914	179,603	26.3%	29.2%	29.2%	32.3%	12.1%
AZ-NM-SNV	21,709	34,997	40,134	40,186	41,170	38.0%	45.9%	46.0%	47.3%	11.7%
CA-MX US	45,318	62,097	60,682	60,682	65,008	27.0%	25.3%	25.3%	30.3%	13.3%
NWPP	43,890	54,594	55,912	55,912	58,291	19.6%	21.5%	21.5%	24.7%	11.9%
RMPA	11,265	13,334	14,426	14,426	14,426	15.5%	21.9%	21.9%	21.9%	10.5%
Total - US	**678,919**	**899,653**	**946,679**	**1,008,489**	**1,105,542**	**24.5%**	**28.3%**	**32.7%**	**38.6%**	**13.0%**
Canada										
MRO	7,909	9,044	9,415	9,415	9,415	12.5%	16.0%	16.0%	16.0%	13.0%
NPCC	62,985	71,695	79,018	81,640	81,782	12.1%	20.3%	22.9%	23.0%	
Maritimes	5,502	6,813	7,038	7,059	7,171	19.2%	21.8%	22.1%	23.3%	13.0%
Ontario	20,952	24,602	30,571	33,172	33,202	14.8%	31.5%	36.8%	36.9%	14.5%
Quebec	36,531	40,280	41,409	41,409	41,409	9.3%	11.8%	11.8%	11.8%	9.1%
WECC	24,104	23,297	25,622	25,622	27,802	-3.5%	5.9%	5.9%	13.3%	10.2%
Total - CAN	**94,998**	**104,036**	**114,055**	**116,677**	**118,999**	**8.7%**	**16.7%**	**18.6%**	**20.2%**	**13.0%**
Mexico										
WECC CA-MX Mex	2,045	1,830	2,257	2,257	2,768	-11.7%	9.4%	9.4%	26.1%	12.5%
Total - NERC	**775,962**	**1,005,519**	**1,062,991**	**1,127,423**	**1,227,309**	**22.8%**	**27.0%**	**31.2%**	**36.8%**	**13.0%**

* *MISO and PJM information does not sum to the RFC total due to the handling of OVEC data. RFC information is only for demand and capacity within its region.*

Table 13e: Estimated 2017 Summer Margins (%), Resources and Demands (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	75,201	72,486	78,843	86,436	116,811	-3.7%	4.6%	13.0%	35.6%	11.1%
FRCC	53,733	51,475	67,434	67,434	67,434	-4.4%	20.3%	20.3%	20.3%	13.0%
MRO	48,625	45,220	50,126	55,984	65,335	-7.5%	3.0%	13.1%	25.6%	13.0%
NPCC	64,145	69,411	72,750	72,750	85,672	7.6%	11.8%	11.8%	25.1%	
New England	28,971	31,246	31,673	31,673	44,596	7.3%	8.5%	8.5%	35.0%	13.0%
New York	35,174	38,165	41,077	41,077	41,077	7.8%	14.4%	14.4%	14.4%	13.0%
RFC	201,700	213,787	219,632	230,875	267,513	5.7%	8.2%	12.6%	24.6%	
RFC-MISO	68,900	70,076	72,540	75,428	80,338	1.7%	5.0%	8.7%	14.2%	12.8%
RFC-PJM	137,000	141,542	144,923	152,940	185,006	3.2%	5.5%	10.4%	25.9%	12.8%
SERC	236,070	234,638	242,498	271,830	302,558	-0.6%	2.7%	13.2%	22.0%	
Central	49,673	47,379	49,983	54,574	67,518	-4.8%	0.6%	9.0%	26.4%	13.0%
Delta	33,144	29,647	29,647	41,251	46,485	-11.8%	-11.8%	19.7%	28.7%	13.0%
Gateway	20,997	23,749	24,314	28,957	28,957	11.6%	13.6%	27.5%	27.5%	13.0%
Southeastern	60,156	61,905	63,587	69,387	78,640	2.8%	5.4%	13.3%	23.5%	13.0%
VACAR	72,100	71,959	74,968	77,661	80,959	-0.2%	3.8%	7.2%	10.9%	13.0%
SPP	49,853	48,390	55,781	64,428	74,354	-3.0%	10.6%	22.6%	33.0%	13.0%
WECC	162,763	166,571	175,838	175,842	187,512	2.3%	7.4%	7.4%	13.2%	12.1%
AZ-NM-SNV	39,442	35,066	37,336	37,340	39,060	-12.5%	-5.6%	-5.6%	-1.0%	11.7%
CA-MX US	64,598	64,515	71,799	71,799	77,976	-0.1%	10.0%	10.0%	17.2%	13.3%
NWPP	44,484	54,127	51,788	51,788	54,861	17.8%	14.1%	14.1%	18.9%	11.9%
RMPA	14,747	12,880	15,418	15,418	16,118	-14.5%	4.4%	4.4%	8.5%	10.5%
Total - US	**892,090**	**901,978**	**962,902**	**1,025,579**	**1,167,189**	**1.1%**	**7.4%**	**13.0%**	**23.6%**	**13.0%**
Canada										
MRO	6,613	7,689	8,297	8,297	8,297	14.0%	20.3%	20.3%	20.3%	13.0%
NPCC	49,349	56,810	64,353	70,123	70,606	13.1%	23.3%	29.6%	30.1%	
Maritimes	3,423	6,526	6,526	6,598	6,756	47.5%	47.5%	48.1%	49.3%	13.0%
Ontario	23,125	18,553	24,522	30,220	30,545	-24.6%	5.7%	23.5%	24.3%	14.5%
Quebec	22,802	31,731	33,305	33,305	33,305	28.1%	31.5%	31.5%	31.5%	9.1%
WECC	22,489	21,889	23,402	23,402	25,686	-2.7%	3.9%	3.9%	12.4%	10.2%
Total - CAN	**78,451**	**86,388**	**96,052**	**101,822**	**104,589**	**9.2%**	**18.3%**	**23.0%**	**25.0%**	**13.0%**
Mexico										
WECC CA-MX Mex	3,598	2,356	2,722	2,722	3,521	-52.7%	-32.2%	-32.2%	-2.2%	12.5%
Total - NERC	**974,139**	**990,722**	**1,061,676**	**1,130,123**	**1,275,299**	**1.7%**	**8.2%**	**13.8%**	**23.6%**	**13.0%**

* *MISO and PJM information does not sum to the RFC total due to the handling of OVEC data. RFC information is only for demand and capacity within its region.*

Table 13f: Estimated 2017/18 Winter Margins (%), Resources and Demands (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	54,085	75,015	81,372	88,965	119,340	27.9%	33.5%	39.2%	54.7%	11.1%
FRCC	55,516	55,116	72,725	72,725	72,725	-0.7%	23.7%	23.7%	23.7%	13.0%
MRO	40,067	42,848	48,019	54,436	63,883	6.5%	16.6%	26.4%	37.3%	13.0%
NPCC	50,760	71,830	73,549	73,549	87,264	29.3%	31.0%	31.0%	41.8%	
New England	22,671	31,246	31,673	31,673	45,382	27.4%	28.4%	28.4%	50.0%	13.0%
New York	28,089	40,584	41,876	41,876	41,882	30.8%	32.9%	32.9%	32.9%	13.0%
RFC	157,900	212,123	217,967	231,959	268,595	25.6%	27.6%	31.9%	41.2%	
RFC-MISO	54,300	67,307	69,771	75,406	80,316	19.3%	22.2%	28.0%	32.4%	12.8%
RFC-PJM	106,800	142,561	145,941	153,958	186,024	25.1%	26.8%	30.6%	42.6%	12.8%
SERC	203,698	229,454	237,973	266,885	298,910	11.2%	14.4%	23.7%	31.9%	
Central	46,444	46,102	48,786	53,343	67,268	-0.7%	4.8%	12.9%	31.0%	13.0%
Delta	26,456	23,717	24,094	35,698	41,036	-11.5%	-9.8%	25.9%	35.5%	13.0%
Gateway	16,835	23,825	24,592	28,768	28,768	29.3%	31.5%	41.5%	41.5%	13.0%
Southeastern	49,625	62,542	64,224	70,024	79,311	20.7%	22.7%	29.1%	37.4%	13.0%
VACAR	64,338	73,269	76,278	79,052	82,527	12.2%	15.7%	18.6%	22.0%	13.0%
SPP	37,592	48,563	54,464	63,650	66,528	22.6%	31.0%	40.9%	43.5%	13.0%
WECC	131,752	164,545	171,100	171,152	181,617	19.9%	23.0%	23.0%	27.5%	12.1%
AZ-NM-SNV	24,525	34,829	40,266	40,318	42,016	29.6%	39.1%	39.2%	41.6%	11.7%
CA-MX US	48,151	61,629	59,063	59,063	64,043	21.9%	18.5%	18.5%	24.8%	13.3%
NWPP	46,858	54,739	56,312	56,312	59,399	14.4%	16.8%	16.8%	21.1%	11.9%
RMPA	12,634	13,363	15,164	15,164	15,864	5.5%	16.7%	16.7%	20.4%	10.5%
Total - US	**731,370**	**899,494**	**957,169**	**1,023,321**	**1,158,862**	**18.7%**	**23.6%**	**28.5%**	**36.9%**	**13.0%**
Canada										
MRO	8,179	9,044	9,509	9,509	9,509	9.6%	14.0%	14.0%	14.0%	13.0%
NPCC	63,827	65,713	73,918	79,957	80,122	2.9%	13.7%	20.2%	20.3%	
Maritimes	5,749	6,813	7,038	7,083	7,219	15.6%	18.3%	18.8%	20.4%	13.0%
Ontario	20,264	18,620	24,589	30,583	30,612	-8.8%	17.6%	33.7%	33.8%	14.5%
Quebec	37,814	40,280	42,291	42,291	42,291	6.1%	10.6%	10.6%	10.6%	9.1%
WECC	26,796	23,284	26,303	26,303	28,483	-15.1%	-1.9%	-1.9%	5.9%	10.2%
Total - CAN	**98,802**	**98,041**	**109,730**	**115,769**	**118,114**	**-0.8%**	**10.0%**	**14.7%**	**16.4%**	**13.0%**
Mexico										
WECC CA-MX Mex	2,648	1,830	2,922	2,922	3,721	-44.7%	9.4%	9.4%	28.8%	12.5%
Total - NERC	**832,820**	**999,365**	**1,069,821**	**1,142,012**	**1,280,697**	**16.7%**	**22.2%**	**27.1%**	**35.0%**	**13.0%**

* *MISO and PJM information does not sum to the RFC total due to the handling of OVEC data. RFC information is only for demand and capacity within its region.*

Notes for Table 13a through 13f

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. Also, the subregional resource numbers include utilization of seasonal demand diversity between the winter peaking northwest and the summer peaking portions of the Western Interconnection.

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

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

Note 6: ISO and PJM information does not sum to the RFC total for two specific reasons:

1) Approximately 100 MW of Ohio Valley Electric Corporation (OVEC)[118] peak demand. OVEC is not affiliated with either PJM or MISO; however, OVEC's Reliability Coordinator services are performed by PJM. RFC information is only for the demand and capacity within its region.
2) RFC reports demand on a non-coincidence basis, while PJM and MISO report a coincident demand.

Note 7: These demand and supply forecasts are as of March 31, 2008.

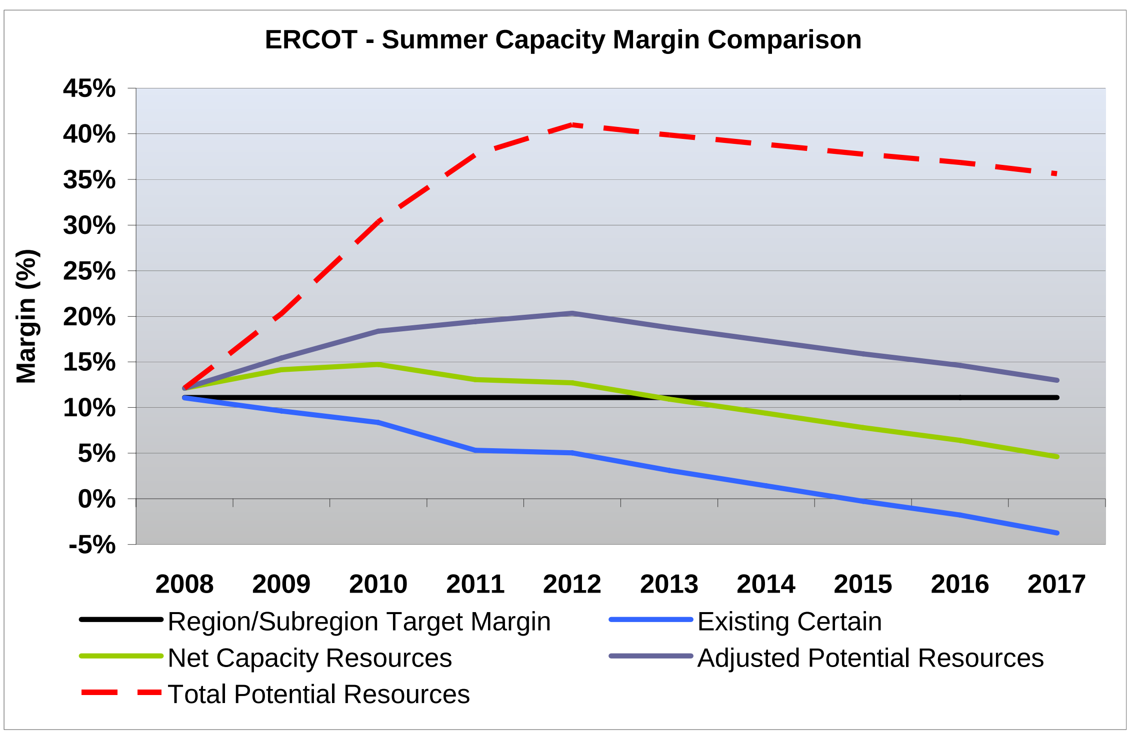
Note 8: Each region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Capacity Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 13 percent capacity margin for predominately thermal systems and for predominately hydro systems, 9 percent.

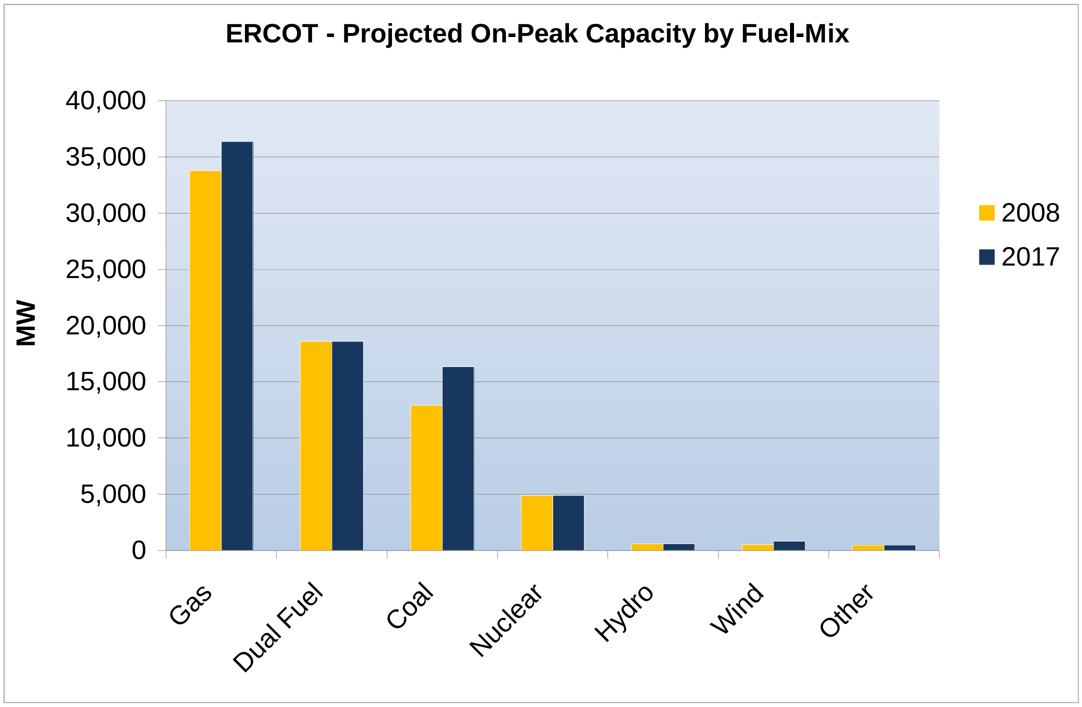
[118] OVEC is a generation and transmission utility located in Indiana, Kentucky and Ohio.

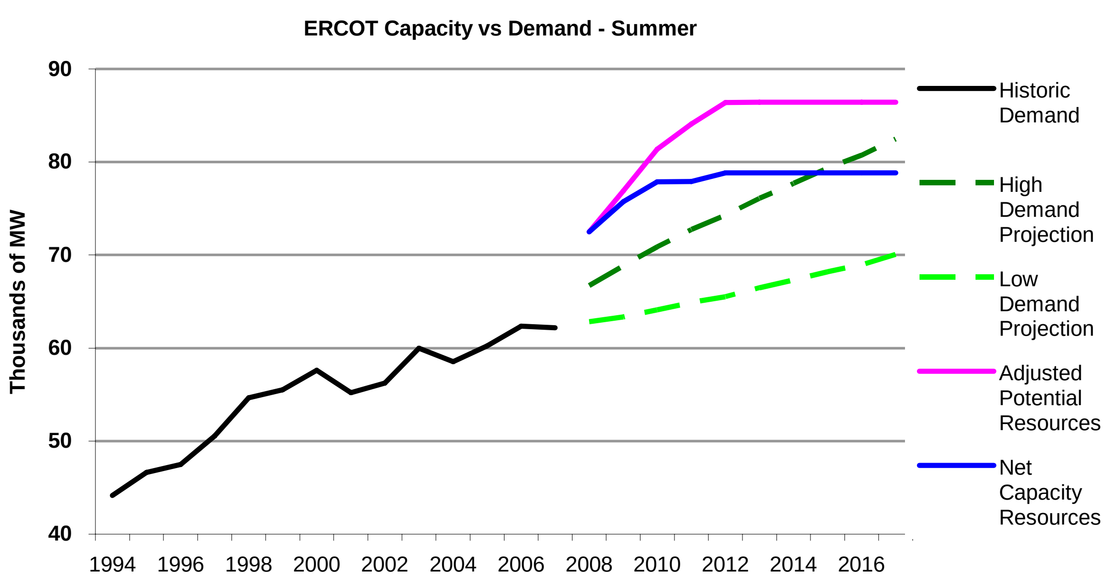
ERCOT Highlights

This year's long-term assessment for resource adequacy in the ERCOT Region is improved over last year's outlook. With additional generating units that have gone into service or have signed interconnection agreements and a lower expectation of load growth due to economic expectations, the annual reserve margin for the region does not drop below the minimum target level of 12.5% until 2013. In addition, 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. The rapid increase in installation of new wind generation is expected to result in congestion on multiple constraints until new transmission lines are added between West Texas and the rest of the ERCOT system. Later this year, the Public Utility Commission of Texas will be completing its Competitive Renewable Energy Zone (CREZ) process, which is expected to result in significant additional bulk transmission that is not reflected in the current assessment. From an operational perspective, the increasing reliance on wind generation is expected to increase operating challenges. Several initiatives are underway, at varying stages of resolution, to ensure the appropriate procedures and requirements are in place to meet these challenges.




ERCOT - Projected On-Peak Capacity by Fuel-Mix
MW
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Gas
Dual Fuel
Coal
Nuclear
Hydro
Wind
Other
2008
2017


ERCOT Capacity vs Demand - Summer
Thousands of MW
90
80
70
60
50
40
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources

ERCOT Self-Assessment

Demand

The 2008 long-term forecast for the ERCOT Region is generally lower than last year's forecast due to the slowdown in the forecasted economic conditions. This is reflected in the average annual growth rate of this year's projected annual growth for 2008-2017 of 1.97% which is lower in comparison to last year's forecasted growth rate for 2007-2016 of 2.25%.

The lower peak demands reflect the expected state of the economy as represented by economic indicators that have been found to drive electricity use in the ERCOT Region's eight weather zones, including real per capita personal income, population, gross domestic product, and various employment measures including non-farm employment and total employment.

In the long-term, real personal per-capita income is expected to level-off or decline in a slight to medium fashion due to wage rates experiencing modest growth, only slightly faster than inflation, due to lower productivity growth. Texas non-farm employment continues to grow faster than the U.S. The gross domestic product (GDP) also shows a lower level and growth rate from 2008 to 2018 when compared to last year's forecast.

Given the net effects of the economic indicators used in the 2008 LTDF forecast, they indicate slowdown of the economy in the long-run. The long-run impact on the forecast due to economic slowdown is projected to start around 2010. Its effects are projected to translate into a 4.50% decline in energy and a 3.31% decline in peak demand by 2018, when compared to last year's forecast.

The forecasted peak demands are produced by ERCOT for the entire ERCOT Region (which is a single Balancing Authority area) based on coincident actual demands. 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. These average weather profiles are based on a Rank-Median method. This method ranks the yearly temperatures from highest to lowest for all years in the database and assigns the ranked temperatures to a calendar. The calendar is selected using a minimum squared error criterion. Median temperatures are preferred as they are not affected as much by outliers as the average.

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.

Two programs are available that explicitly modify the forecasted peak demand for the region. The LaaRs program (Load Acting as a Resource) which amounts to approximately 1059 MW. The LaaR capacity is available through ERCOT's ancillary services market. In addition, the Texas Legislature increased the mandatory amount of energy efficiency reduction in demand that each investor-owned utility in ERCOT must achieve. The effect of this increase on system peak demand is expected to be 143MW in 2008 and 160MW in 2009 and thereafter.

To assess the impact of weather variability on the peak demand for ERCOT, alternative weather scenarios are used to develop extreme MW forecasts. A high demand scenario is produced using the 90th percentile of the temperatures in the database spanning the last fourteen years available. The lower temperatures that rank in the bottom 10th percentile of the database are also used to produce a lower range forecast.

The extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The higher temperature assumptions consistently produce MW forecasts that are approximately 5.5% higher than the base forecasts (50/50). Together the forecasts from these temperature scenarios are usually referred to as 90/10 MW forecasts.

Generation

The amount of Existing Certain capacity is 70,886 MW for the summer periods. Of this amount, 480 MW is from wind generation and 53MW is from biomass. Existing Uncertain[118] capacity is 9,231 MW, of which 4,979 MW is from wind generation. Planned capacity[119] additions range from 864 MW in 2008/2009 to 6,357 MW starting in 2011 / 2012 and continuing through the assessment period. Wind generation accounts for 371 MW of this Planned amount. Proposed capacity[120] resources expected to be in-service amount to 5,787 MW in 2009 / 2010 and increasing to 37,968 MW in 2013 / 2014 through the rest of the study period. Wind capacity accounts for 3,728 MW of this Proposed amount

Purchases and Sales on Peak

ERCOT has only limited planned purchases and sales with other regions. There is approximately 50 MW tied to a long term contract for purchase from the SPP region of firm power and transmission (on SPP side) from specific generation. There are no other known purchases existing or under study.

SPP members' ownership of 247 MW of a power plant located in ERCOT results in a transfer of this amount from ERCOT to SPP. There are no other known firm sales from the ERCOT Region existing or under study. ERCOT does not share reserves with entities outside the region but does have emergency support agreements with both CFE and SPP.

Fuel

Over 60% of the generating capacity in ERCOT is fueled by natural gas, resulting in some concern about the adequacy of natural gas supply during winter months when winter heating demand peaks. Natural gas interruptions are not typically a concern during the summer, when electric power demand peaks. ERCOT has a procedure in place to request current status of fuel supply contracts, back-up fuel supplies and unit capabilities if severe cold weather is in the seven day forecast. This information would be used to prepare operation plans. However, there is currently no market incentive or non-market mechanism for gas generation to maintain dual fuel capability and storage, typically with fuel oil, that could be critical to maintaining generation adequacy during extended periods of gas curtailments. .

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[118] Existing Uncertain capacity includes the portion of the wind generation that is not counted as Certain due to its variability and the existing generating capacity that is mothballed

[119] Planned capacity additions include new generation that has a signed interconnection agreement and air permit, with wind generation counted at its effective load carrying capability. Planned capacity additions are included in reserves.

[120] Proposed capacity additions include all other generation that has requested interconnection agreement, with wind generation counted at its effective load carrying capability. Proposed capacity additions are not included in reserves.

ERCOT will initiate its Emergency Electric Curtailment Plan (EECP)[121] if available capacity gets below required levels due to gas curtailments or any other reason. The EECP maintains the reliability of the interconnection by avoiding uncontrolled load shedding.

Transmission –

Planned Improvements identified for the first time in this year's assessment include a new 345 kV transmission line in the East weather zone to alleviate the need for a special protection system (SPS), a new 345 kV switching station in northwest Houston to increase North to Houston transfer capability, and additional autotransformer and 138 kV line upgrades in the Dallas-Fort Worth metropolitan area. In addition, two new 345 kV transmission lines and a new 345 kV switching station were included in the West region due to the additional wind generation in the West region. Additional findings of the assessment are:

- The numbers of planned transmission circuit miles and autotransformer additions for the next five years have increased from the level included in last year's five year plan.
- Continued rapid increase in the installation of new wind generation in West Texas is expected to result in congestion on multiple constraints and West to North transfers until new bulk transmission lines are added between West Texas and the rest of the ERCOT system.

The Public Utility Commission of Texas will be completing its Competitive Renewable Energy Zone (CREZ) process this summer. This process may result in significant additional plans for bulk transmission.

Operational Issues

No major facility outages, regulatory restrictions, or environmental requirements are currently expected during the assessment period that would significantly impact reliable operations. Ongoing operational challenges during the assessment period are expected to center around transmission congestion management and operating with reduced capacity reserve margins.

The continued increase in installed wind generation has the potential to increase operating challenges. ERCOT has recently implemented a wind power forecasting system to allow operators to take appropriate actions when changes or increased uncertainty in wind power output are forecasted. In addition, congestion management associated with the increased wind generation is likely to require increased attention. Finally, ERCOT recently completed a study of the impact of increased wind generation in ancillary services requirements, which are expected to increase at the projected levels of installed wind generation.

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 EECP in the future.

The major market redesign, approved by the Public Utility Commission of Texas (PUCT) will change current congestion management procedures from a zonal to a nodal-based system. This transition, which will occur during the assessment period, may present challenges in implementing new operating computing systems but should also improve the efficiency of transmission congestion management.

[121] See ERCOT Protocols Section 5.6.6.1 at http://www.ercot.com/mktrules/protocols/current.html

Reliability Assessment Analysis

ERCOT has an adequate reserve margin through 2012 but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2013, 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, resulting in no more than one day in ten years loss of load, performed in 2005.

ERCOT almost entirely uses internal resources to serve its load and reserves, with the exception of a 50 MW purchases from SPP and emergency support agreements with SPP and CFE. ERCOT has 71,750 MW of installed generation (summer), with additional signed interconnection agreements for 5,987 MW of new fossil fuel generation and 371 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.

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 5.5% 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 Emergency Electric Curtailment Plan (EECP) (See Section 5.6.6.1 of the ERCOT Protocols)[122]. The EECP includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the DC ties, ISO-instructed demand response procedures and are in place and are described in the ERCOT Operating Guides Section 4.5 Emergency Electric Curtailment Plan (EECP). [123]

Only 8.7% 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. The remaining existing wind capacity amount is included in the Uncertain generation amount.

There are no 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[124]).

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

ERCOT has interconnections through DC ties with the Eastern Interconnect and with Mexico. The maximum imports/export over these ties is 1,106 MW. These ties can be operated at a maximum import and export provided there are no area transmission elements out of service. In the event of a transmission outage in the area of these ties, studies will be run during the outage coordination period for the outages to see if any import/export limits are needed.

The Public Utility Commission of Texas will be completing its Competitive Renewable Energy Zone (CREZ) process this summer. This process may result in significant additional plans for bulk transmission to enable wind generation in West Texas to be able to serve load in the rest of the ERCOT Region.

The continued rapid installation of new wind generation in West Texas is expected to result in congestion on multiple constraints within and out of West Texas for the next several years until new bulk transmission lines are added between West Texas and the rest of the ERCOT system. This is not expected to limit deliverability during peak periods, since only 8.7% of the installed wind capacity is counted for reserve purposes.

ERCOT regularly performs transient dynamics and voltage studies. Small signal stability studies were performed as part of the West-North stability study. There are no anticipated stability issues that could affect reliability, however ERCOT closely monitors a west-north stability limit and a Rio Grande valley voltage limit.

In the operations planning horizon, ERCOT 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.

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.

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. These areas and mitigation procedures are found in Operating Procedure 2.4.3.[125] ERCOT plans for a 5% voltage stability margin for category A and category B contingencies and a 2.5% margin for category C contingencies[126]. 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.

UVLS schemes are deployed in the following areas: Houston ~ 4500 MW, DFW ~ 3500 MW, 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

[125] http://www.ercot.com/mktrules/guides/procedures/TransmissionSecurity_V3R89.doc
[126] http://www.ercot.com/mktrules/guides/operating/2007/07/05/05-070107.doc

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 & 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 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 types of systems would lead to loss of significant amounts of generating capacity. ERCOT is not currently experiencing drought conditions and reservoir levels are currently at or near full capacity nor does it expect significant capacity reduction implications due to low water levels.

Transmission Service Providers (TSPs) and ERCOT perform a full battery of steady-state and dynamic contingency analyses on an on-going basis to test the performance of the planned system against the standards of TPL-001 through TPL-004. The TSPs are responsible for resolving unacceptable results through the provision of Transmission Facilities, etc. in accordance with Op. Guide 5.1.4. Additional transmission system upgrades are planned to resolve any future problems, resulting in the planned transmission discussed in the Transmission section. .

ERCOT has recently implemented a wind power forecasting system to allow operators to assess differences with the resource plans submitted by scheduling entities for wind generation and take appropriate actions.

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. Fault currents in the region have not yet exceeded the levels for which for which applications using commercially available 345kV breakers can be designed. The ERCOT region does not have guidelines for on-site, spare generator step-up (GSU) and auto transformers. Individual transmission owners may participate in programs to share spare transformers, but the region as a whole does not.

Other region-specific issues that were not mentioned above

ERCOT will be implementing a new market design and related systems during the assessment period which should allow for more efficient management of congestion. Entities in the ERCOT Region are handling workforce retention and recruitment issues independently.

Region Description

The ERCOT Region is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. Texas RE, a functionally independent division of ERCOT, performs the regional entity functions described in the Energy Policy Act of 2005 for the ERCOT region. ERCOT has 251 members that represent independent retail electric providers; generators, and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking region responsible for about 85 percent of the electric load in Texas with a 2006 peak demand of 62,339 megawatts. ERCOT serves a population of more than 20 million in a geographic area of about 200,000 square miles. Additional information is available on the ERCOT web site.

FRCC Highlights

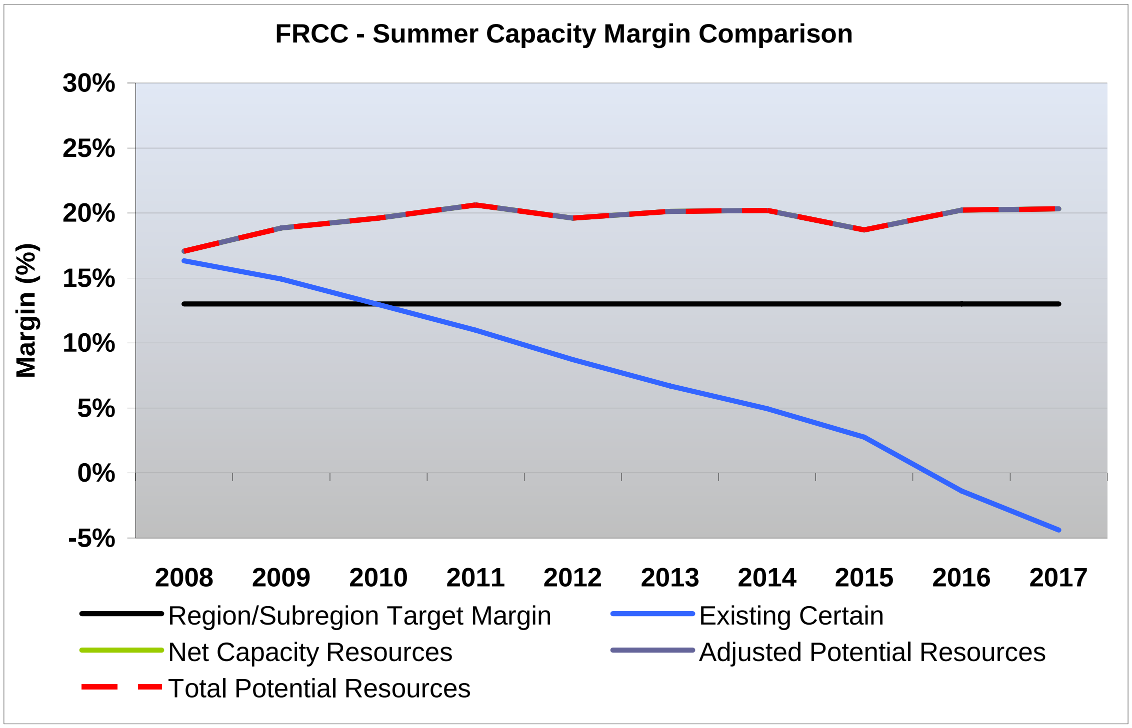
All Florida utilities are required to meet the Florida Public Service Commission (FPSC) reserve margin. Therefore, much of the resources in the 6-10 year timeframe are not sited, rather represent industry's obligation to meet this reserve margin. While FRCC reports adequate resources through 2017, not sited plants are included in the data provided in the self assessment. Much of these planned generation resources are not sited but are considered committed by FRCC and deemed to be deliverable.

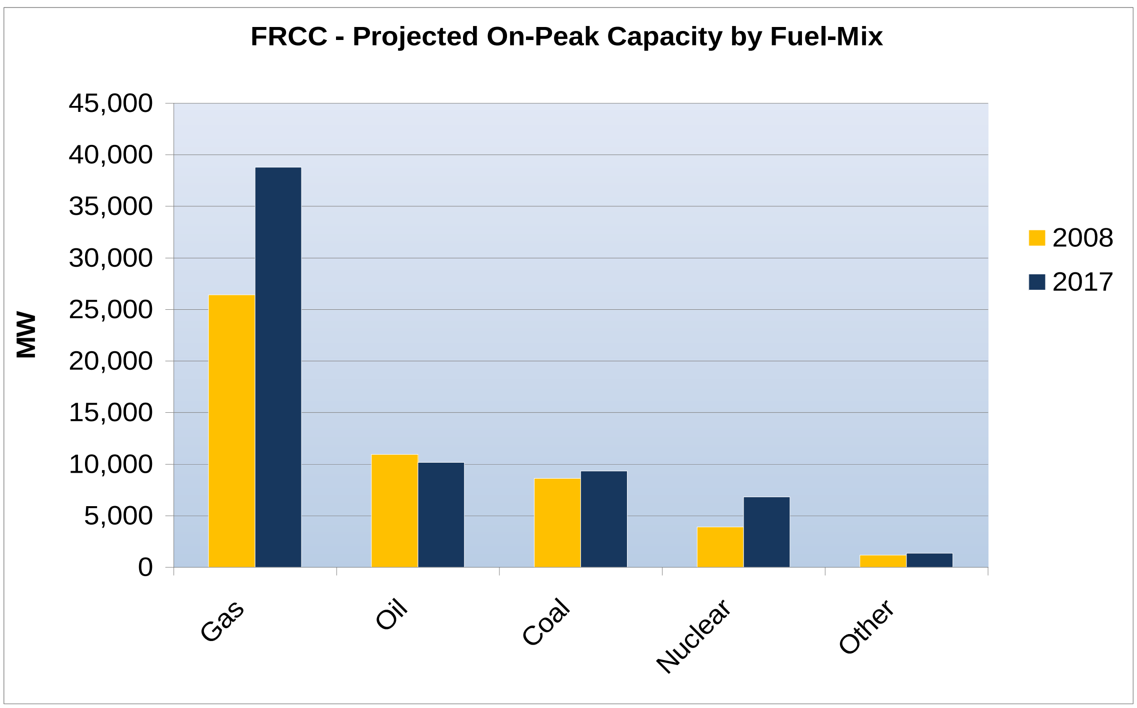
Based on the aforementioned, the Florida Reliability Coordinating Council (FRCC) expects to have an adequate generating reserve margin with transmission system deliverability throughout the 2008-2017 reliability assessment to meet the forecasted growth in peak demand and energy through the same time frame. The FRCC Region expects to serve the forecasted firm peak demand and energy requirements reliably through 2017 by adding a net 15,959 MW of resources. In addition, existing uncertain merchant plant capability of 1966 MW is available by 2017 as potential future resources of FRCC members and others.

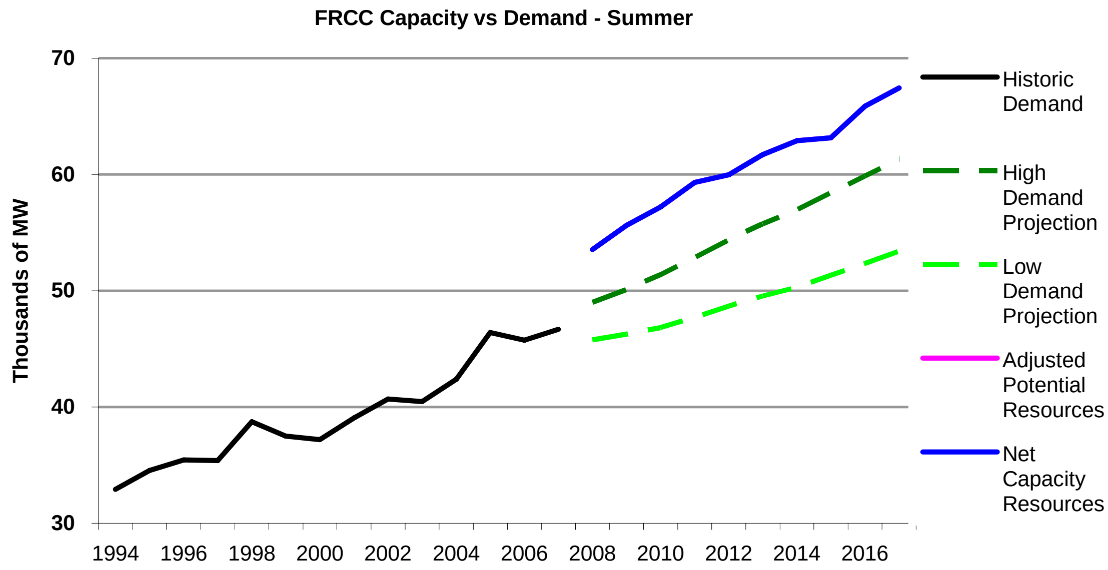
The transmission capability within the FRCC is expected to be adequate to supply firm customer demand and to provide planned firm transmission service. In order to maintain an adequate transmission system, the FRCC members plan to construct 508 miles of 230 kV and 80 miles of 500 kV transmission lines through 2017. Operational issues in the Central Florida area are expected through the summer of 2010. Unplanned outages of generating units may aggravate the transmission system serving the Central Florida area. However, it is anticipated that existing operational procedures, pre-planning and training will adequately manage and mitigate the impacts to the bulk transmission system in the Central Florida area. After 2010, planned transmission improvements in the Central Florida area are expected to mitigate these operational issues.

The FRCC Region meets the NERC's TPL Standards by performing the required transmission assessments representing the 10 year planning horizon. The FRCC Region develops detailed transmission assessments for the 1-5 year time frame recognizing the fact that generation expansion plans are known with a higher degree of confidence and most planned transmission projects and corresponding in-service dates are known.

The FRCC Region performs transmission assessments representing the 6-10 year time frame recognizing the uncertainties related to future generation siting and corresponding transmission expansion to support future generation and load growth. All Florida utilities are required to meet the Florida Public Service Commission (FPSC) reserve margin. Therefore, even if future generation plans are not firm, the utilities must show that they plan to maintain these reserve margin levels throughout the planning horizon. Approximately half of the generation planned in the 6-10 year time frame us not sited and may require additional transmission sensitivity assessments. The transmission system is evaluated in the 6-10 year time frame to identify possible emerging concerns, monitor known concerns, monitor the effects of planned projects and identify major projects that may require long lead times. In addition, the transmission expansion plans representing the years 6-10 are typically under review by most transmission owners still considering multiple alternatives for each project.


FRCC - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


FRCC - Projected On-Peak Capacity by Fuel-Mix
MW
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Gas
Oil
Coal
Nuclear
Other
2008
2017


FRCC Capacity vs Demand - Summer
Thousands of MW
70
60
50
40
30
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources

FRCC Self-Assessment

Introduction

FRCC expects to have adequate generating capacity reserves with transmission system deliverability throughout the 10 year period. In addition, existing uncertain merchant plant capability raging from 1,054 MW to 1966 MW is available as potential 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 the impacts to the bulk transmission system.

Demand

FRCC uses historical weather databases consisting of as much as 58 years of data for the weather assumptions used in their forecasting models. Historically, the 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.

The aggregated peak demand in the FRCC region for 2007 was 46,676 MW as compared to a peak demand forecast of 46,878 MW. The 2008 ten year demand forecast for the FRCC region exhibits a compounded average annual growth rate of 2.1 percent over the next ten years compared to last year's compounded average annual growth rate of 2.2 percent. The 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. The 2008 ten year net internal demand forecast includes the effects of 3,613 MW of potential demand reductions from the use of load management (1,834 MW of residential & 1,073 MW of commercial/industrial) and interruptible demand (706 MW) by 2017.

FRCC employs two different techniques to assess the peak demand uncertainty and variability. First, FRCC develops regional bandwidths or 80 percent confidence intervals on the projected demand. The 80 percent confidence intervals on peak demand can be interpreted to mean that there is a 10 percent probability that in any year of the forecast horizon that actual observed load could exceed the high band. Likewise, there is a 10 percent probability that the actual observed load in any year could be less than the low band in the confidence interval. The purpose of developing bandwidths on peak demand 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.

Monte Carlo simulations on peak demands are performed to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes of peak demand. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability is incorporated into the simulations. The regional aggregated peak demand for the FRCC is established using these simulations.

Generation

FRCC supply-side resources considered for this 10 year assessment are categorized as Existing Certain, Existing Uncertain and Planned. The FRCC Region counts on 50,629 MW of Existing Certain resources of which 55 MW are hydro and 462 MW are Biomass.[127] There are a total of 1,054 MW of Existing Uncertain resources identified for 2008 and increasing to 1,966 MW by 2017. In addition, there are a total of 476 MW of Planned resources for 2008 of which 11 MW are Biomass. Planned resources by 2017 are expected to be 15,959 MW of which 201 MW are categorized as Biomass

FRCC entities have an obligation to serve and this obligation is reflected within each entity's 10-Year Site Plan file annually with the Florida Public Service Commission. Therefore, FRCC entities consider all future capacity resources as "Planned" and included in Reserve Margin calculations.

Purchases and Sales

The FRCC Region does not consider non-firm, expected or provisional purchases and sales as capacity resources in the determination of the Region's Reserve Margin. The expected firm interregional purchases for 2008 are 2,448 MW and expected to decrease by 2017 to 846 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

Fuel

Although the FRCC has reviewed various types of fuel supply vulnerability issues in the past, the increased reliance of generating capacity on natural gas has caused the FRCC to address this fuel type specifically. The FRCC continues coordination efforts among natural gas suppliers and generators within the region. The recently revised FRCC Generating Capacity Shortage Plan[128] includes specific actions to address capacity constraints due to natural gas availability constraints and includes close coordination with the pipeline operators serving the Region. The FRCC Operating Committee has also developed the procedure, FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers[129], to enhance the existing coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators and in response to FERC Order 698.

Currently, the expected percentage of generation capacity whose primary fuel is natural gas is 58% and that whose primary fuel is coal-fired is 14% within the FRCC Region by 2017. Presently, the FRCC Region is not anticipating any fuel supply and/or delivery problems for either natural gas or coal.

Transmission

Currently, individual transmission owners plan to construct 508 miles of 230 kV and 80 miles of 500 kV transmission lines during the 2008-2017 planning horizon. The existing transmission system of the FRCC Region consists of 1,350 miles of 500 kV transmission lines and approximately 5,850 miles of 230 kV transmission lines.

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[127] 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.

[128] See pages P6:2-32 of the document: https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Handbook%200208.pdf

[129] https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Communications%20Protocols%20102207.pdf

Operational Issues

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. In addition, there are no foreseen environmental and/or regulatory restrictions that can potentially impact reliability in the FRCC region throughout the assessment period.

Reliability Assessment Analysis

The Florida Public Service Commission (FPSC) requires all Florida utilities to file an annual Ten Year Site Plan[130] that details how each utility will manage growth for the next decade. The data from the individual plans is aggregated into the FRCC Load and Resource Plan[131] that is produced each year and filed with the Florida Public Service Commission. The FRCC 2008 Load and Resource Plan shows the average FRCC Reserve Margin of 29% over the winter peaks and a 24% Reserve Margin over the summer peaks for the next ten years. The 15% (20% for Investor Owned Utilities) Reserve Margin criteria required by the FPSC applies to all 10 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 load serving entity.

The 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 2006 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 FRCC is planning to conduct the next LOLP analysis by 2009.

The amount of resources internal to the region or subregion that are relied on to meet the minimum 15% Reserve Margin throughout the assessment period varies from 51,104 MW to 66,588 MW. The amount of resources external to the region/subregion that are relied on to meet the Reserve Margin for the assessment period vary from 2,448 MW to 846 MW by 2017.

FRCC is projecting a net increase (i.e., additions less removals) of 15,959 MW of new installed capacity over the next decade, compared to the 14,792 MW projected by last year's ten-year forecast. Of this net increase, 12,842 MW are designated for gas-fired operation in either simple-cycle or combined-cycle configurations, 738 MW[132] are anticipated for coal-fired operation, 2,927 MW designated as new and upgraded nuclear, 201 MW are designated as Biomass, and 749 MW are related to oil-fired units that have been de-rated, retired and/or

130 https://www.frcc.com/Planning/default.aspx?RootFolder=%2fPlanning%2fShared%20Documents%2fTen%20Year%20Site%20Plans%2f2008&FolderCTID=&View=%7bFBDE89E4%2dE66F%2d40EE%2d999D%2dCFF06CF2A726%7d

131 https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plan/2008%20LRP_Web.pdf

132 The expected coal-fired generation decreased by 3889 MW since 2007 primary due to environmental concerns at the State level. The majority of this decrease in planned coal-fired generation was replaced with gas-fired units.

converted to another fuel type. Gas-fired generation continues to dominate a high percentage of new generation. It is forecast that electrical energy produced from natural gas generators will increase from 40 percent in 2007 to 55 percent in 2017.

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 the 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/or 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, the FRCC does not anticipate any fuel transportation issues affecting capability during peak periods and/or extreme weather conditions.

The FRCC ensures resource adequacy by maintaining a minimum 15% 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, DLC (HVAC, Water Heater, and Pool Pump), Voltage Reduction, customer stand-by generation, emergency contracts and unit emergency capability.

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 Electric System (BES). In addition, the FRCC Transmission Working Group evaluates planned generator additions to ensure the proposed interconnection and/or integration is acceptable to maintain the reliability for the BES within the FRCC Region. Presently, the FRCC has not identified any deliverability concerns with regards to firm resources.

Availability and deliverability of external resources are ensured by firm transmission service, purchase power contracts and transmission assessments. These external resources were included in the “FRCC Long Range Study (2009 – 2017)” demonstrating the deliverability of these resources and no deliverability concerns identified.

Major transmission additions required to support the addition of new resources in the 2013 – 2017 time frame include, but not limited to, major 500 kV (~80 miles) and 230 kV (~160 miles) transmission lines. Construction of 500 kV transmission lines is considered to be a long lead time project.

The FRCC Region is planned and operated such that NERC Reliability Standards are met without the need to identify any specific criteria for minimum dynamic reactive reserve requirements or transient voltage-dip criteria. Transient and dynamic stability studies are performed by the FRCC and no issues have been identified that would impact years 1-5 of the time period. Small signal analysis is performed when damping issues are identified during transient and/or dynamic stability studies. Voltage security assessments performed in the Region involve identifying the worst case conditions such as the unavailability of multiple units. In addition, the FRCC has performed load sensitivity analyses in the short term time frame using available load models representing induction motors and no issues have been 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 bulk power system. The “FRCC Long Range Study (2009 – 2017)” did not identify any reactive power-limited areas that would impact the bulk electric system during the entire planning horizon time period. The FRCC Region has not identified the need to develop specific criteria to establish a voltage stability margin.

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 targeted by UVLS throughout the planning horizon time period.

Based on past operating experience with hurricane impacts to the fuel supply infrastructure within the Region, the FRCC revised its Generating Capacity Shortage Plan[133] in 2007. 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.

Currently, the FRCC Region is not experiencing a drought and therefore, no reliability impacts due to a drought are anticipated over the next few years.

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL-001 through TPL-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.

[133] https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Handbook%200208.pdf, pages P6:2-32

The results of the short-term (first five years) study for normal, single and multiple contingency analysis of the FRCC region show that 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.

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. Based on the committed projects and expected generation dispatch, it is expected that these remedial actions will continue in this area through 2010. Permanent solutions consisting of new proposed facilities and the rebuilding of existing facilities have been identified and implementation of these solutions is underway. Some of these proposed facilities include constructing a new 230kV transmission line from West Lake Wales to Intercession City and rebuilding the existing transmission line from West Lake Wales to Intercession City.

The long-range (remaining five years) study results reveal developing thermal and voltage issues in several areas in the FRCC region which the responsible utilities have studied in more detail. These areas include northwest Florida around Tallahassee and the Avon Park area northwest of Lake Okeechobee. The northwest Florida issues are being addressed by interregional coordination and proposed projects expected to be in-service beginning in the summer of 2009 and extending through 2013. The Avon Park area issues are being addressed by implementing a Special Protection Scheme and converting an existing 115 kV transmission line to 230 kV.

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. However, 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.

Transmission owners within the FRCC Region have the responsibility to address short circuit levels within their system. Any potential short circuit concerns identified by interconnection studies or other studies are addressed by the individual transmission owner. Resolution of short circuit concerns is typically addressed by replacing existing equipment, adding equipment and/or reconfiguring the system. Presently, the FRCC Region has not identified any short circuit mitigation techniques that are projected to impact reliability.

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.

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.

Other Region-Specific Issues that were not mentioned above

The FRCC is not anticipating any other reliability concerns throughout the 10 year study period. Unexpected potential reliability real-time issues identified by the Reliability Coordinator can be resolved with existing operational procedures.

Industry entities within the FRCC Region address workforce retention and recruitment issues by providing various monetary and non-monetary compensation strategies. Some of these strategies may include higher base pay, end of year bonus, stock options with a vested time frame, signing bonus, additional vacation, work from home options and improved health, medical and dental benefits.

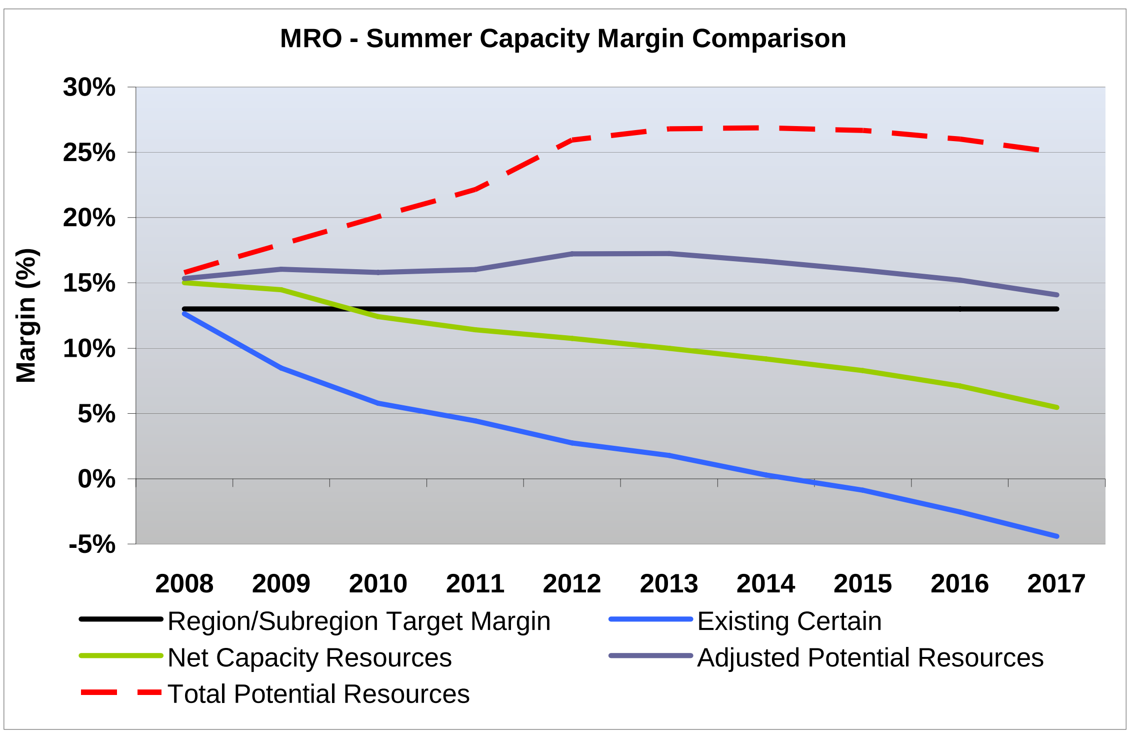
Region Description

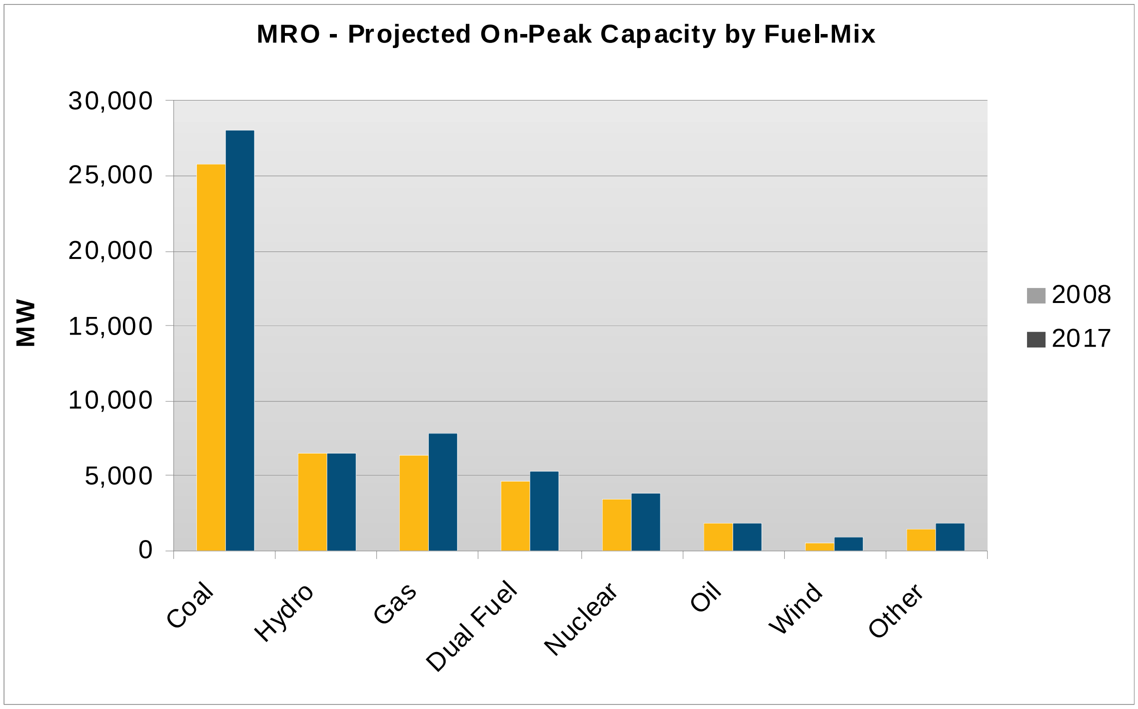
FRCC's membership includes 26 members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. Historically, the region has been divided into 11 Balancing Authorities. As part of the transition to the ERO, FRCC has registered 79 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).

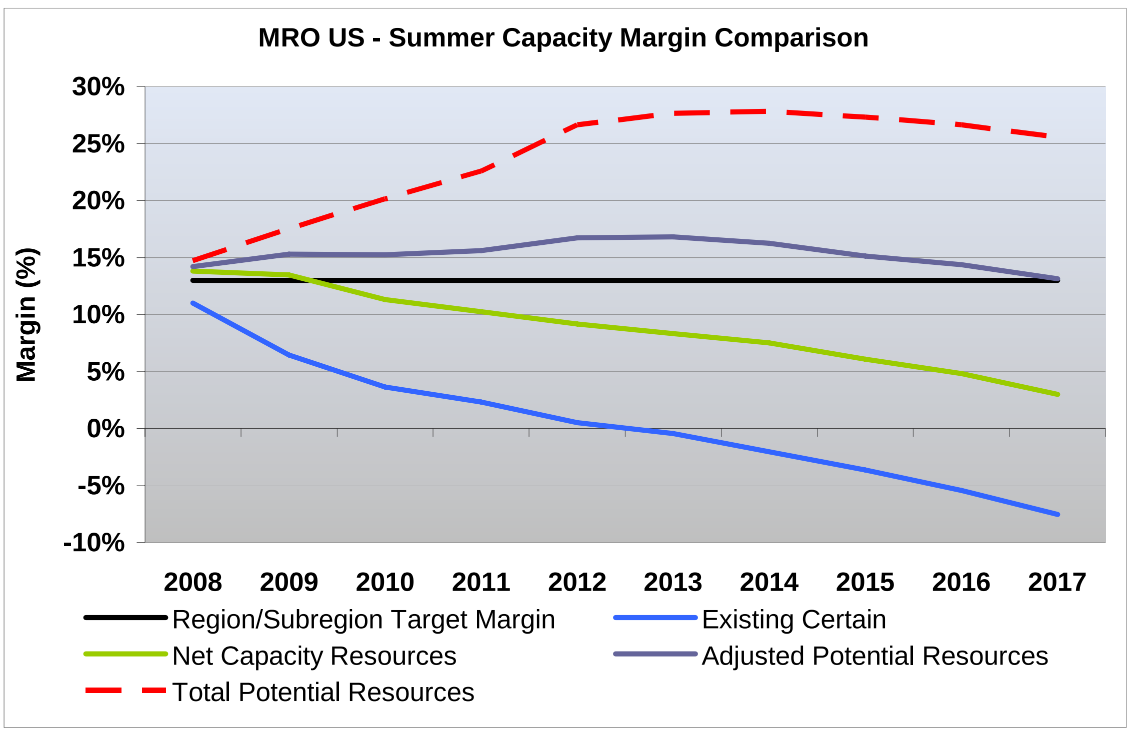
MRO Highlights

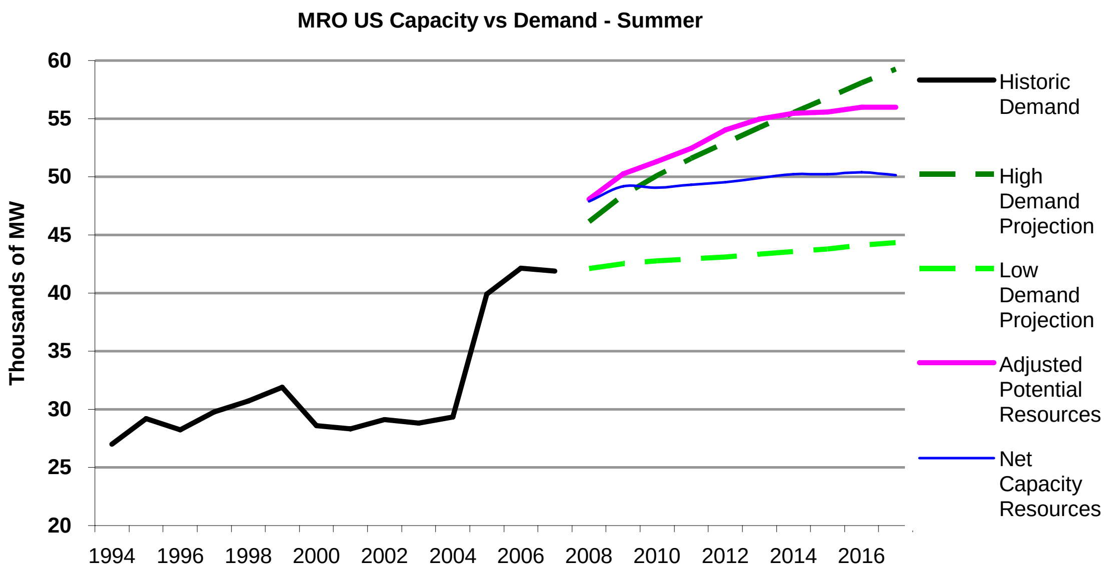
Sufficient generating capacity is expected within the Midwest Reliability Organization to maintain adequate capacity margins through 2017. Through the 2017 planning horizon, the MRO expects its transmission system to perform adequately, assuming proposed reinforcements are completed on schedule. The MRO Transmission Owners estimate that 833 miles of 500 kV DC, 1,068 miles of 345 kV, and 996 miles of 230 kV transmission will be installed in the MRO region over the next ten years.

The next ten years will see a very rapid load growth in the oil fields and coal bed methane fields at the Bakken Formation in western North Dakota and eastern Montana. Constructing adequate facilities to handle this growth is on a fast tract. Also during the 2008-2017 period, a very large amount of wind generation will be expected to be added in the MRO footprint. In 2017, the existing wind generation plus the planned and proposed wind generation would be serving about 16% of the projected MRO net internal demand at summer peak. Operating the system with the wind generation additions in the MRO region will be a challenge.

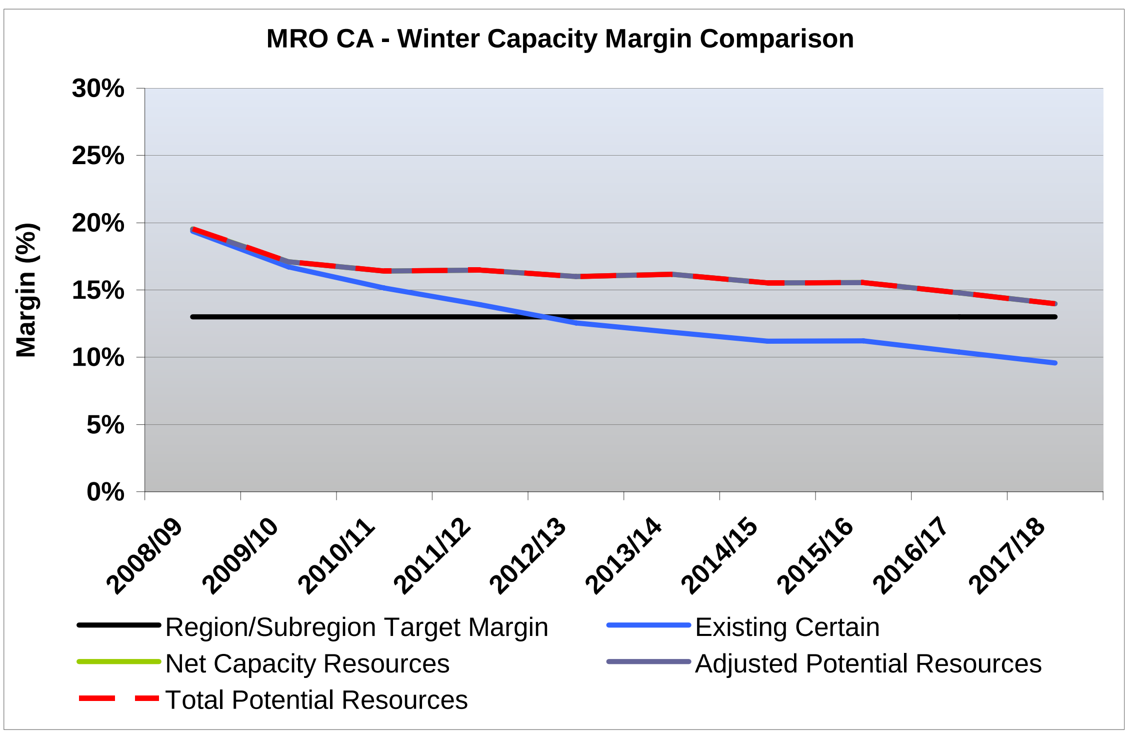



MRO - Projected On-Peak Capacity by Fuel-Mix
MW
30,000
25,000
20,000
15,000
10,000
5,000
0
Coal
Hydro
Gas
Dual Fuel
Nuclear
Oil
Wind
Other
2008
2017

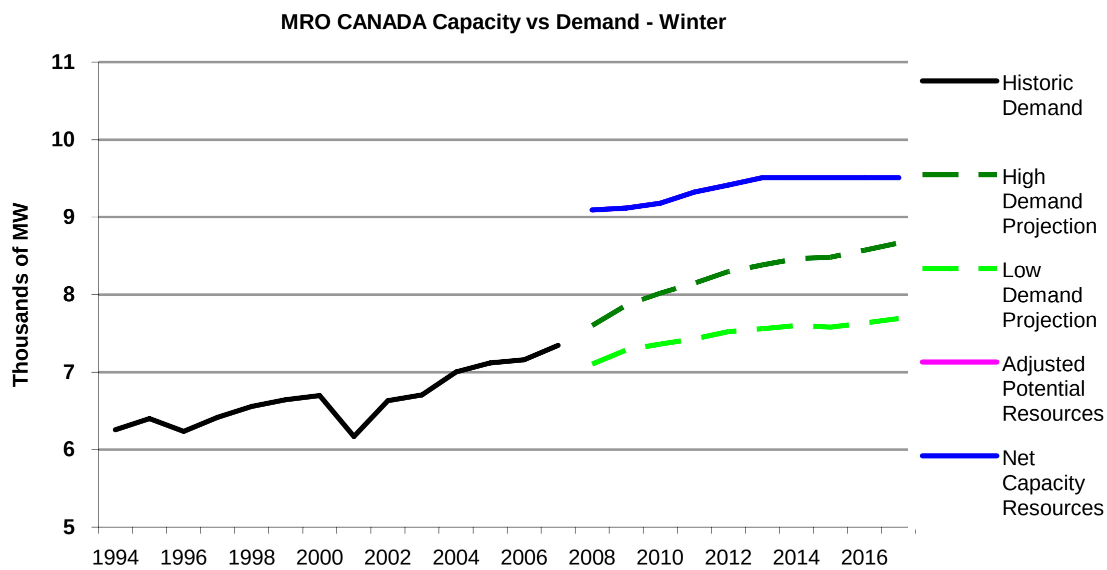

MRO US - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
-10%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources



MRO US Capacity vs Demand - Summer
Thousands of MW
60
55
50
45
40
35
30
25
20
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources



MRO CA - Winter Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


MRO CANADA Capacity vs Demand - Winter
Thousands of MW
11
10
9
8
7
6
5
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources

MRO Self-Assessment

Introduction

Sufficient generating capacity is expected within the Midwest Reliability Organization to maintain adequate capacity margins through 2017. Through the 2017 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, 1,068 miles of 345 kV, and 996 miles of 230 kV transmission will be installed in the MRO region over the next ten years.

The next ten years will see a very rapid load growth in the oil fields and coal bed methane fields at the Bakken Formation in western North Dakota and eastern Montana. Constructing adequate facilities to handle this growth is on a fast tract. Also during the 2008-2017 period, a very large amount of wind generation will be expected to be added in the MRO footprint. In 2017, the existing wind generation plus the planned and proposed wind generation would be serving about 16% of the projected MRO net internal demand at summer peak. Operating the system with the wind generation additions in the MRO region will be a challenge.

The 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. The MRO membership consists of the former and existing members of the MAPP Generation Reserve Sharing Pool (GRSP), members from the former Mid-America Interconnected Network, Inc. (MAIN),[134] and Saskatchewan Power Corporation (SaskPower), one of the two Canadian members.[135] The new bulk power system transmission facilities are, however, described by geographical areas in the MRO footprint: Minnesota, Nebraska, Dakotas, Iowa, and Wisconsin in the MRO-U.S., and Manitoba and Saskatchewan in the MRO-Canada.

Demand

Each MRO member's peak demand forecast includes factors involving expected economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. 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 1.8% per year during the 2008–2017 period, as compared to 2.3% predicted last year for the 2007–2016 period. This year's projection of 1.8% compares closely with the 1.9% predicted two years ago for the 2006–2015 period. The

[134] The former MAIN members are Alliant Energy, Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric. The American Transmission Company (ATCLLC) is the transmission owner which encompasses the last four former MAIN members and Alliant Energy-Wisconsin Power & Light, which is the Wisconsin portion of Alliant Energy. The ITC Midwest is the transmission provider for the Iowa and Minnesota portion of Alliant Energy.

[135] The other Canadian member is Manitoba Hydro which, for the purpose of this assessment, is included in the MAPP GRSP group.

higher growth rate predicted last year can be attributed to higher trending resulting from actual 2006 demands that occurred within the region. Factors that can influence higher trending from year to year are weather extremes and economic assumptions.

The MRO-Canada summer peak net internal demand is expected to increase at an average rate of 1.3% per year during the 2008–2017 period, as compared to 1.1% predicted last year for the 2007–2016 period. While the MRO region as a whole is summer-peaking, the MRO-Canada is a winter-peaking sub-region. The MRO-Canada winter peak demand is expected to increase at an average rate of 1.2% per year during the 2008–2017 period, as compared to 1.0% predicted last year for the 2007–2016 period. The higher winter peak growth rate predicted this year stems from the new loads (mining, chemical plants, pipelines, and ethanol plants) requesting connections that were committed in the last forecast.

MRO staff sent the NERC spreadsheets to each Load Serving Entity within the MRO region and collected individual member's load forecast data. MRO staff then combined the individual inputs from these spreadsheets to calculate the MRO regional totals without applying a diversity factor to the regional demand.

Interruptible Demand and Demand Side Management (DSM) programs, presently amounting to approximately 6.2% of the MRO's Projected Total Internal Peak Demand, are used by a number of MRO members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load are used to reduce peak demand.

Generation

Existing resources considered as "Certain" amount to 52,900 MW for 2008. Existing "Uncertain" resources amount to 3,397 MW for 2008. The "Planned" resources for the MRO region amount to 1,518 MW starting in 2008 and are estimated to increase to 5,514 MW by 2017. The "Proposed" resources for the MRO region amount to 591 MW starting in 2008 and are estimated to increase to 14,727 MW by 2017. All these capacity numbers are net expected on-peak values.

Existing wind generation amounts to 3,997 MW of nameplate capacity for summer 2008. Assuming a 20% capacity value,[136] 799 MW of the nameplate amount is expected to be "Certain" (available at peak load). Wind generation that is "Planned" for the next 10 years amounts to 1,028 MW nameplate, with an expected on-peak value of 213 MW.

A significant portion of the "Proposed" resources consists of wind generation. This is based on generation within the Midwest ISO interconnection queue that is in the MRO Region. "Proposed" on-peak wind resources are expected to be 467 MW starting in 2008 and increasing to 7,895 MW by 2017. The "Proposed" nameplate wind generation for the MRO Region amounts to 2,336 MW in 2008 and increasing to 39,713 MW in 2017.

[136] This assumption is based on the fact that the Midwest ISO allows a capacity credit of 20 percent of nameplate capacity for wind generation. That would account for most, but not all of the wind capacity within the MRO region. MRO members, like those who are MAPP members, also submitted data for their existing wind facility, as well as future planned facilities. As the result, the MRO overall on-peak value may not necessarily equal 20 percent of nameplate capacity.

Existing Biomass generation amounts to 275 MW and is estimated to increase by only 76 MW over the next 10 years. This generation is typically expected to be available on peak.

For this year's assessment, NERC has re-defined how resources are reported. Existing resources are categorized as either "Certain" or "Uncertain." Future resources are categorized as either "Planned" or "Proposed." Three capacity margins are calculated for the 10-year period:

- Existing Certain + Planned
- Existing Certain + Planned + 100% of Proposed
- Existing Certain + Planned + (Proposed x Confidence Factor)

Since the "Proposed" generation was primarily determined from the MISO generation interconnection queue, a confidence factor was applied by MRO staff to reduce the proposed amount to a realistic expected value. Confidence factors were higher in the earlier years since these resources were assumed to be more likely to be built. In later years, a 20% confidence factor was applied, which is consistent with actual generation realized historically from interconnection queues.

There are uncertainties involved when using a generation interconnection queue. In-service dates can be deferred or slip. Similarly, some generation that is expected within the next several years may in fact qualify as "Planned" resources. MRO staff worked with generation owners to verify/update in-service dates of key future generation (i.e., large coal units) and to establish reasonable confidence factors. In establishing these confidence factors, MRO staff also considered that the LSEs within the MRO region have an obligation to serve.

The confidence factors applied for each year are:

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
50%	45%	40%	35%	35%	35%	20%	20%	20%	20%

For the purposes of this assessment, capacity margins using adjusted proposed resources will be compared to target margin levels.

Purchases and Sales

For 2008, the MRO is projecting total firm purchases of 1,787 MW from sources external to the MRO region. The MRO has projected 731 MW of total sales to load outside the MRO region. Both purchases and sales become progressively lower in future years. This is typical and purchases/sales will likely increase as each year approaches. By NERC definition, capacity margins are to be calculated using the net firm interchange. However, the net import/export of the MRO region can vary at peak load, depending on system conditions and economic conditions. For example, firm exports may not necessarily be scheduled on during internal peak load periods.

Firm transactions from the MRO-Canada (Saskatchewan and Manitoba) into the MRO-U.S. are limited to 2,415 MW due to the operating security limits of the two interfaces between the two provinces and the United States. Firm transactions from MRO-Canada into the MRO –U.S. reflex existing and future long term contractual transactions. For example, for summer 2008, approximately 1,400 MW of firm transactions from Manitoba Hydro into the MRO-U.S. is expected. These long-term firm sale transactions are based on dependable energy expected to be available under the lowest recorded historic water flow (drought) conditions in Manitoba.

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

Transmission providers within the MRO region treat Liquidated Damage Contracts according to their individual tariff policies. Most MRO members are within non-retail access jurisdictions (except for Upper Michigan), and therefore liquidated damages products are not typically used.

Most MRO members count on firm capacity from outside of the region for emergency and reserve sharing requirements. However, Saskatchewan does not rely on outside resources. It self-supplies all planning and operating reserves.

Fuel

49% of existing MRO generation is coal-fired, and 13% is natural gas-fired. The MRO considers known and anticipated fuel supply or delivery issues in its assessment. Because there is a large diversity in fuel supply, inventory management, and delivery methods throughout the region, the MRO does not have a specific mitigation procedure in place should fuel delivery problems occur. The MRO and its members closely monitor the delivery of Powder River Basin coal to ensure adequate supply. The MRO does not foresee any significant fuel supply and/or fuel delivery issues in the near future.

In Saskatchewan in particular, fuel-supply vulnerability is generally not considered an issue due to system design and operating practices:

- Coal resources (approximately 47% of generating capacity) have firm contracts and are mine mouth, and also stock is 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. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves are either 30 or 65 days depending on the coal facility.
- Natural gas resources (approximately 25% of generating capacity) have firm transportation contracts with large natural gas storage facilities located within the province backing those contracts up.
- Hydro facilities and reservoirs are fully controlled by SaskPower.

Transmission

Minnesota

Transmission companies in the Minnesota Area are jointly pursuing major transmission infrastructure investment through the CapX 2020 (CapX) 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 CapX proposed Brookings, SD - Twin Cities 345 kV line may benefit the flowgate of North Dakota Export, and may impact the Lakefield - Lakefield Generation 345 kV line, Fox Lake - Rutland 161 kV line, Rutland - Winnebago 161 kV line, and the Lakefield - Fox Lake 161 kV line. Further wind farm development in this region will continue to recreate the flowgate issues unless continued transmission investment is made in the region.

The CapX proposed Twin Cities - North Rochester - La Crosse 345 kV line may impact several flowgates, such as the Minnesota - Wisconsin Export Interface, Prairie Island - Byron 345kV, and other lower voltage flowgates that exist in the Minnesota/western Wisconsin areas. It is expected that this line will redefine the Minnesota - Wisconsin Export Interface.

Nebraska
Western Area Power Administration and Nebraska Public Power District plan to install a third 250 MVA 345/230 kV transformer at the Grand Island substation by the summer of 2009. Both 187 MVA 230/115 kV transformers at the North Platte substation will be replaced with new 336 MVA 230/115 kV transformers by 2009.

Due to rapid load growth in the east central Nebraska region, a Columbus/Norfolk Transmission Expansion Plan, targeted for completion by the summer of 2010, was developed.

The Public Power Generation Agency plans to construct a second coal-fired generating unit at the existing Whelan Energy Center Site near Hastings, Nebraska, which is expected to begin commercial operation in the spring of 2011 with a net output of 220 MW.

The Omaha Public Power District (OPPD) is constructing a second coal-fired generating unit at the Nebraska City Power Station, which is expected to begin commercial operation in the spring of 2009 with a net output of 700 MW.

Lincoln Electric System plans to install a second 345/115 kV transformer at the NW68th & Holdrege substation, with an in-service date of 2010. LES will construct a 26-mile 345 kV line from the Wagener substation to the NW68th & Holdrege substation, around the northern perimeter of Lincoln, with an in-service date of 2009.

Dakotas
About 50 facility additions are scheduled between 2008 and 2014. Facility additions range from new substation equipment such as capacitor bank additions and transformers to new transmission line additions. Unexpected load growth in the oil fields and coal bed methane fields at the Bakken Formation in western North Dakota and eastern Montana has led to a large increase in load in some isolated areas. This unexpected load growth has resulted in individual substation loads that were less than 10 MW at the start of the decade to those projected to be approaching 100 MW now. Facilities to handle this growth are on a fast track.

Near-term major transmission projects under construction include two 230 kV transmission lines, one from Belfield to a new tap of the Little Missouri - Bowman line called Rhame, and the other from Williston to Tioga. Both are planned for completion by fall 2009.

Out-year projects planned include 230 kV transmission additions in the Huron-Storla area in South Dakota scheduled for 2014.

Iowa

The Iowa system is beginning to experience several regional forces including an increase in installed wind power in Minnesota, northern Iowa, and central Illinois, recent base load generation near Council Bluffs followed by Nebraska City (2009), and the development of several new spot loads from ethanol plants. Power from wind and coal in western Iowa (and Nebraska) should decrease east – west transfers, while future additional Illinois wind power could again increase east – west and possibly south – north transfers. New large spot loads from ethanol plants should absorb some of the new generation. The combination of wind and coal generation along with new load will continue to require new transmission to adequately meet transmission planning criteria.

The Iowa companies have several 115 kV, 161 kV, and 345 kV projects planned over the next several years to reinforce Iowa.

Wisconsin

Significant transmission and transformer additions planned to be in-service during 2008-2017 will strengthen the reliability of the Wisconsin-Upper Michigan Systems (WUMS) for summer 2008 and subsequent years.

The WUMS southern interface contains four 345 kV lines and one 138 kV tie line. This interface is thermally limited for critical N-1 contingencies and voltage stability limited for critical N-2 contingencies during periods of heavy transfers across the interface. Operating guides are used to monitor and manage the constraints during high imports into WUMS across the southern interface. The American Transmission Company (ATCLLC) has plans to add a new 345 kV transmission line between the Rockdale and Paddock 345 kV substations that will help to alleviate the southern interface constraints. This 345 kV line is expected to be in-service in 2010.

Heavy power flows into Michigan's Upper Peninsula (UP) from northeast Wisconsin is expected to continue. The corridor consisting of the three 138 kV lines south of the Morgan and Stiles substations continues to be a potential constraint that could lead to thermal and voltage violations under contingencies during periods of high flows towards the UP. This constraint is monitored and managed by following an operating guide. Completion of new Werner West – Highway 22 – Morgan and Gardner Park – Highway 22 345 kV lines in late 2009 will help to alleviate this constraint.

Manitoba

For normal operations with all facilities in service, the Manitoba Hydro system demonstrates adequate performance in terms of facility loading and voltages with various operating conditions for the 2008-2017 period. There are no existing constraints from a system planning perspective.

The projects listed below are now underway or planned in the next decade and will keep the Manitoba Hydro transmission system operating satisfactorily 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. The following are the major projects in the Manitoba area:

- 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, including:
  - Two Wuskwatim-Herblet Lake lines – 2009
  - Herblet Lake-The Pas Ralls Islands line – 2010
  - Thompson Birchtree static VAR compensator – 2011
- Dorsey Bus Enhancement consists of the Dorsey 230 kV bus being improved with the addition of four 230 kV circuit breakers and a new connecting bus.
- New 500/230 kV Reil Station consists of establishing a new station which will include:
  - Installing a 500/230 kV transformer bank
  - Sectionalizing the existing Dorsey – Forbes 500 kV line
  - Sectionalizing two existing parallel 230 kV lines from Ridgeway to St. Vital
- Bipole III transmission line runs from Conawapa Station in the north to Riel Station near Winnipeg. The Bipole III scheme with a west side of the province routing 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
  - Five AC transmission lines approximately 19 miles in length each to connect the Conawapa Converter Station to the northern collector system
  - 2,000 MW converter station at Riel, including four synchronous compensators
- Winnipeg Area Transmission Refurbishments consist of an estimated 114 miles of 230 kV transmission lines that will be upgraded to carry higher loading.
- 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 230/66 kV transformers are being added to the system. The sites include the Rosser, Transcona, Stanley, and Neepawa stations.

Saskatchewan

Addition of a 99 mile 230 kV transmission line and a 350 MVA 230/138 kV autotransformer in south central Saskatchewan in 2010 is planned to mitigate post-contingency overloads and provide voltage support in the area.

Operational Issues

No significant operational concerns are expected. Operating studies and guides 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.

Completion of the Arrowhead – Stone Lake – Gardner Park 345 kV line provides the needed transmission reinforcement on the Wisconsin-Upper Michigan System (WUMS) western interface with Minnesota and improves both the WUMS and MRO transmission reliability and transfer capability. Studies have demonstrated that with high imports into WUMS from Minnesota, there is potential transient voltage recovery violation and voltage instability and therefore determined the need for a new interface flowgate comprised of Arrowhead-Stone Lake 345 kV line and King-Eau Claire 345 kV line, called the Minnesota Wisconsin Export (MWEX) Interface. This interface is managed as a reciprocal Interconnection Reliability Operating Limit Flowgate of Midwest ISO and MAPP. The existing Minnesota Wisconsin Stability Interface will be retained for prior outage conditions and to gain operational experience with MWEX. The existing operating guides for the King – Eau Claire – Arpin 345 kV line and the Arpin – Rocky Run 345 kV line will be revised accordingly.

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 of these potential impacts, however, is unknown at this time.

Reliability Assessment Analysis

For the purpose of this assessment, the MRO used a 15% region-wide reserve margin as a proxy measure of resource adequacy, which is representative of the range of reserve margin targets for the various groups within the MRO, as described below:

- For the MAPP GRSP members, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP requires a 15% reserve capacity obligation (RCO) for predominantly thermal systems, and a 10% RCO for predominantly hydro systems.[137] The RCO is established by the MAPP Restated Agreement and its governing authorities, i.e. MAPP Executive Committee and MAPP Pool Committee. This level of reserve requirements is subject to periodic review based on reserve requirements studies conducted regularly by MAPP.[138] The RCO requires the MAPP GRSP members to maintain their respective minimum reserve based on after-the-fact peak demand; i.e., the members are responsible for maintaining adequate generation to account for load forecast uncertainty. When a new peak occurs, the member will be required to maintain the minimum reserve based on that peak for the next 11 months, or until a new, higher peak takes place. For summer 2008, approximately 8,850 MW of generation in the MAPP GRSP (15.7% of MRO net internal capacity) is associated with predominantly hydro systems and only requires a 10% RCO.
- For the former MAIN members, generation resource adequacy is assessed based on LOLE studies previously conducted by the MAIN region.[139] Although conducted on a

[137] The MAPP GRSP Handbook, http://www.mappcor.org/assets/pdf/GRSP_Handbook_20070116.pdf.

[138] The previous MAPP reserve requirements study was conducted in 2003 by the MAPP Composite System Reliability Working Group. This study is not posted on the MAPP website, but it is available upon request from Brian Glover, MAPPCOR (651-855-1715 or bp.glover@mappcor.org). The MAPP 2008 LOLE Study is ongoing and is expected to be completed by October 1, 2008.

[139] In the former MAIN region, MAIN Guide 6 adopted a resource adequacy criterion of 0.1 days/year, http://www.maininc.org/bg/guide6.pdf. Studies concerning LOLE calculations for the former MAIN Region are available. The 2005 study is located at http://www.maininc.org/files/MG6GenerationReliabilityStudy2005_14.pdf. Other studies are found by navigating through http://www.maininc.org/files/files.htm.

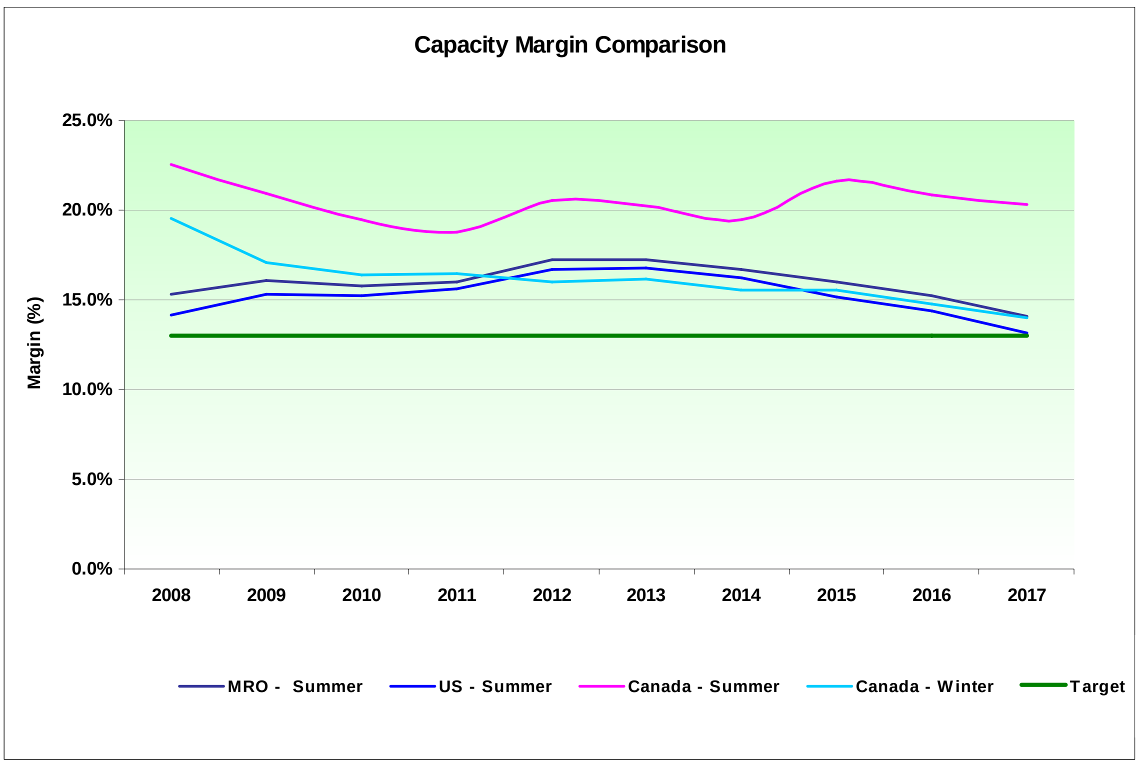
yearly basis, MAIN's LOLE studies consistently recommended a minimum long-term planning reserve margin of 16%.

- Saskatchewan's reliability criterion is based on annual expected unserved energy (EUE) analysis and equates to an approximate 15% reserve margin requirement.[140]

Since NERC requests that capacity margins be used, a 13% region-wide capacity margin is used as a proxy measure of resource adequacy (target level) in the MRO region. A 15% planning reserve margin equates to a 13.04% capacity margin. Using the "Proposed" resources after they have been appropriately adjusted by the confidence factors, the projected capacity margins for the MRO region, MRO-U.S., and MRO-Canada are as follows:

- MRO-Total**:** The summer peak capacity margins for the full MRO region range from 17.2% to 14.1% for the 2008-2017 period.
- MRO-U.S.**:** The summer peak capacity margins for the MRO-U.S. sub-region range from 16.8% to 13.1% for the 2008-2017 period.
- MRO-Canada**:** The summer peak capacity margins for the MRO-Canada subregion range from 22.6% to 18.7% for the 2008-2017 period. For winter peak, the MRO-Canada capacity margins range from 19.5% to 14.0% for the 2008-2017 period.

The graph below shows these projected capacity margins graphically, which all exceed the target capacity margin of 13%.



[140] Saskatchewan Power's generation adequacy studies for the province of Saskatchewan are not publicly posted or released. Information regarding these studies may be obtained by contacting SaskPower.

The former MAIN members now within MRO use a minimum long-term planning reserve margin of 16% and a minimum short-term planning reserve margin of 14%. For the remainder of the MRO, reserve margin requirements do not vary based on short term vs. long term.

This year's assessment cannot be readily compared with last year's assessment due to the significant changes in how resources were defined and accounted for. Last year's assessment only included "Committed" future resources when calculating capacity margins. Consequently capacity margins did not meet target levels for most of 10 year period for most regions. This year, a portion of "Proposed" resources are being included from generation interconnection queues. The projected capacity margins based on this year's resource definitions should more accurately capture future generation than last year's assessment.

The MRO members accounted for resource unavailability being higher than expected due to fuel interruptions or other conditions such as extended drought or forced outages, and peak demands being higher than expected due to extreme weather (e.g., 90/10 forecast) or other conditions within the determination of adequate generation reserve margin levels, as follows:

- Both the MAPP Generation Reserve Sharing Pool members and the former MAIN members within MRO consider generator forced outage rate increase and load forecast uncertainty within their Loss of Load Expectation (LOLE) studies to determine the target reserve margin levels that satisfy the LOLE criteria of 0.1 day per year or 1 day in 10 years.
- For Saskatchewan, a winter-peaking system, winter peak load is forecasted on a heating season basis and represents the highest level of demand placed on the supply system. The winter forecast is normalized to account for cold weather based on a 30-year average weather pattern. Forecasts are developed for Saskatchewan 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 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% is attached to the likelihood of the load falling within the bounds created by the high and low forecasts.

The MRO region does not count on energy-only, existing-uncertain wind and transmission-limited resources for reliability purposes.

None of the planned unit retirements within the MRO Region will have a significant impact on reliability.

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/

Throughout the MRO region, firm transmission service is required for all generation resources that are used to provide firm capacity; therefore, these firm generation resources are fully deliverable to the load.

No specific analysis was performed by MRO to evaluate whether external resources are available and deliverable. However, the MAPP GRSP, former MAIN utilities, and Saskatchewan require external purchases to have a firm contract and firm transmission service to be counted as firm capacity.

The major transmission additions required to support the addition of new resources and new loads in the MRO in the 6-10 year period include the following:

- The network upgrades identified for the addition of a 280 MW generating unit at Nelson Dewey include a new 161 kV transmission line approximately 15 miles long from ATCLLC's Nelson Dewey substation in Wisconsin to a new ITC Midwest's switching station located between the existing Liberty and Lore 161 kV substations in.[141] The expected in-service year for the generation and the required network upgrades is 2013.
- The new 230 kV transmission facilities in the western Minnesota area will be required for the proposed Big Stone II generation project planned to be on-line in 2013. Some of this new transmission may be designed for operation at 345 kV.
- The CAPX 345 kV line from Brookings, SD to the Twin Cities, MN 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. The expected service date is 2014.

There are no stability issues that could impact the reliability anticipated during the reported period. The following is information on stability-related criteria used within the MRO:

- For MAPP members, the specific MAPP bulk transmission reliability criteria and study methods, assumptions, and procedures are outlined in the *MAPP Member Reliability Criteria and Study Procedure*[142] and the *MAPP Design Reliability Subcommittee Policies and Procedures*.[143] Those criteria are to be used for MAPP planning and operating studies.
- For the former MAIN members, dynamic reactive margin is part of the ATCLLC Planning Criteria, which is determined using a reduction to the reported reactive capability of synchronous machines. A 10 percent dynamic reactive margin is required in the intact system and a 5 percent dynamic reactive margin is required under NERC Category B contingencies. ATCLLC has transient voltage dip criteria. Voltage recovery is required to be within 70 percent and 120 percent of nominal immediately following the clearing of a disturbance. Voltage recovery is required to be within 80 percent and 120 percent of nominal between 2.0 and 20 seconds following the clearance of a disturbance. Due to many years of coordinated planning as a MAPP member in the past, ITC Midwest retains the MAPP criteria.

[141] G527 Interconnection Facilities Study Report available at http://oasis.midwestiso.org/documents/ATC/Cluster_8_Queue.html
[142] http://www.mapp.org/assets/pdf/Reliability%20Criteria%20Studies%20Manual/As%20of%20November%202004.pdf
[143] http://www.mapp.org/assets/policies/DRS%20Policies%20and%20Procedures_February%202008.pdf

- Saskatchewan addresses dynamic reactive requirements through operating guides and planning studies. No stability issues are anticipated that will impact reliability in Saskatchewan. Saskatchewan's guideline for post-disturbance transient voltage dip is 0.7 p.u. and 1.2 p.u.

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.

Several members within the MRO region have localized UVLS programs to prevent localized low voltage conditions. These programs are not required to protect the bulk power system.

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. Operational measures, which would include emergency plans, interruptible load contracts, public appeals, and rotating outages, would be implemented as necessary.

The MRO region as a whole is not experiencing a drought. However, reservoir water levels continue to remain low in Montana, North Dakota, and South Dakota, and will reduce the magnitude and duration of power transfers out of the Dakotas. As a result, there will likely be non-firm imports of power from south and east of the MRO region into the MRO region to replace the energy reduction associated with these low water levels. The Manitoba water condition is normal. Therefore, normal Manitoba-US exports are likely.

TPL001 – TPL004 planning studies are performed in the MRO region by the various groups, as follows:

- For MAPP and ITC Midwest, a Reliability Assessment Study is performed annually by the MAPP Transmission Planning Subcommittee and its Transmission Reliability Assessment Working Group. 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 conducted on model years 2008, 2012 and 2017 for winter peak, summer peak, and summer off-peak with high transfer conditions. Dynamic analysis was conducted on 2011 and 2012 summer off-peak with high transfer models.
- Based on the TPL-001 - TPL-004 planning studies performed by ATCLLC,[144] reliable operation of the WUMS transmission system is expected during the 2008-2017 assessment period.

[144] 2007 – ATCLLC 10-Year Transmission System Assessment Update, http://www.atc10yearplan.com. Also refer to Reliability First Corporation (RFC) Long Term Transmission Assessment Studies (on-going), https://www.rfirst.org, http://www.maininc.org/

- Saskatchewan performs ongoing system assessments as part of its planning process to integrate new generation and load.

The MRO region uses special protection systems (SPS) to enhance reliability and currently has 53 SPSs in place. These systems allow the owners to meet TPL-001 through TPL-003 Standards per NERC Standard PRC-012. Certain MRO members also use SPSs to meet TPL-004.

New technologies, systems, and tools that are expected to be deployed (or continue to be deployed) to improve bulk power system reliability within the MRO region includes:

- Distributed Superconducting Magnetic Energy Storage Devices,
- Certain High Temperature Low Sag conductors, and
- Software tools such as Physical and Operational Margins/Optimum Mitigation, Production Cost Modeling, Voltage Stability Analysis Tool, and Power World.

In addition, MRO members participate in the review and development of new technologies, systems, and tools through the research activities of the Electric Power Research Institute, Power System Engineering Research Center, and CEATI International Inc.

The MRO region Transmission Owners evaluate short circuit levels on an on-going basis, and forecasted short circuit levels are currently well below available nameplate interrupting ratings.

Companies within the 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.

Policies or guidelines for on-site, spare generator step-up (GSU) transformers and autotransformers in the MRO region are, as follows:

- ATCLLC does not own any spare GSU transformers but owns many medium and large spare autotransformers. 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 STEP program.
- Saskatchewan does not have a guideline for GSU transformers; however it does have a spare GSU transformer for major base load 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 share spare transformers with other companies.
- For the rest of the MRO region, the need for spare transformers is decided on a case-by-case basis.

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 will be reported in more detail in the MRO Scenario Assessment. This report will be provided to NERC in May 2009.

In 1992, conventional base load generation (coal, hydro, nuclear) amounted to 90% of the total generation in the former MAPP Region, which is now a major portion of the MRO. In 2008, conventional base load generation amounts to about 73% of the total generation within the MRO. Over the next ten years, planned and proposed wind generation on a nameplate basis makes up about 77% (40,740 MW out of 52,873 MW) of the resource additions within the MRO Region, based on the Midwest ISO generation interconnection queue. Assuming that all of the planned and proposed wind generation will be built, and assuming that the expected on-peak value of the wind nameplate capacity (8,108 MW) is available and deliverable at peak load, this would amount to about 40% of the projected 20,240 MW total for new resources expected to be available during peak load in 2017. Therefore, the existing wind generation (799 MW) plus the planned and proposed wind generation would be serving about 16% of the projected MRO net internal demand of 55,238 MW at peak load in 2017.

As part of the preparation of this assessment, MRO staff attempted to collect information on how the workforce retention and recruitment issues are dealt with, from Planning Authorities (PA) within the MRO region. The responses from the PAs did not provide sufficient information to formulate a clear description of the subject.

Assessment Process

To prepare this MRO regional self-assessment, MRO staff sent the NERC spreadsheets to the registered entities within the MRO and collected individual entity's load forecast, generation, and demand-side management data. The staff then combined the individual inputs from these spreadsheets to calculate the MRO regional totals. The staff also sought responses to the questions included in the NERC LTRA request letter, from Planning Authorities within the MRO region – MAPP, ATCLLC, and SaskPower. The MAPP Transmission Planning Subcommittee and its Transmission Reliability Assessment Working Group also provided detail on the various MAPP planning studies. Using the information gathered from this process, the MRO Resource Assessment Subcommittee prepared the resource assessment portions, while the Transmission Assessment Subcommittee prepared the transmission assessment and operational issues portions. Finally, the MRO Reliability Assessment Committee, which is ultimately responsible for the long-term reliability assessments, reviewed and approved the final draft before it was submitted to NERC.

Region Description

The Midwest Reliability Organization (MRO) has 48 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and/or Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant and Transmission System Operator. The MRO has 19 Balancing Authorities and 115 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

NPCC Highlights

For the ten year study period of the 2008 Long-Term Reliability Assessment, the resource plans of each of the five Areas (subregions) of NPCC meet the NPCC resource adequacy criterion which obligates each Area to ensure that its probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. When compared with the RAS Long-Term Reliability Assessment conducted in 2007 for the 2007-2016 time frame, margins have improved overall. The projected rate of load growth has decreased in four of the five Areas due to slowing economic activity. In Ontario, there is an active commitment to energy conservation and a reduction in customer load which is also reflected in its decline in load growth. Only the province of Québec forecasts a slight increase in load growth over its projections for 2007. The currently planned transmission system over the ten-year period is expected to perform reliably for a range of contingencies and conditions.

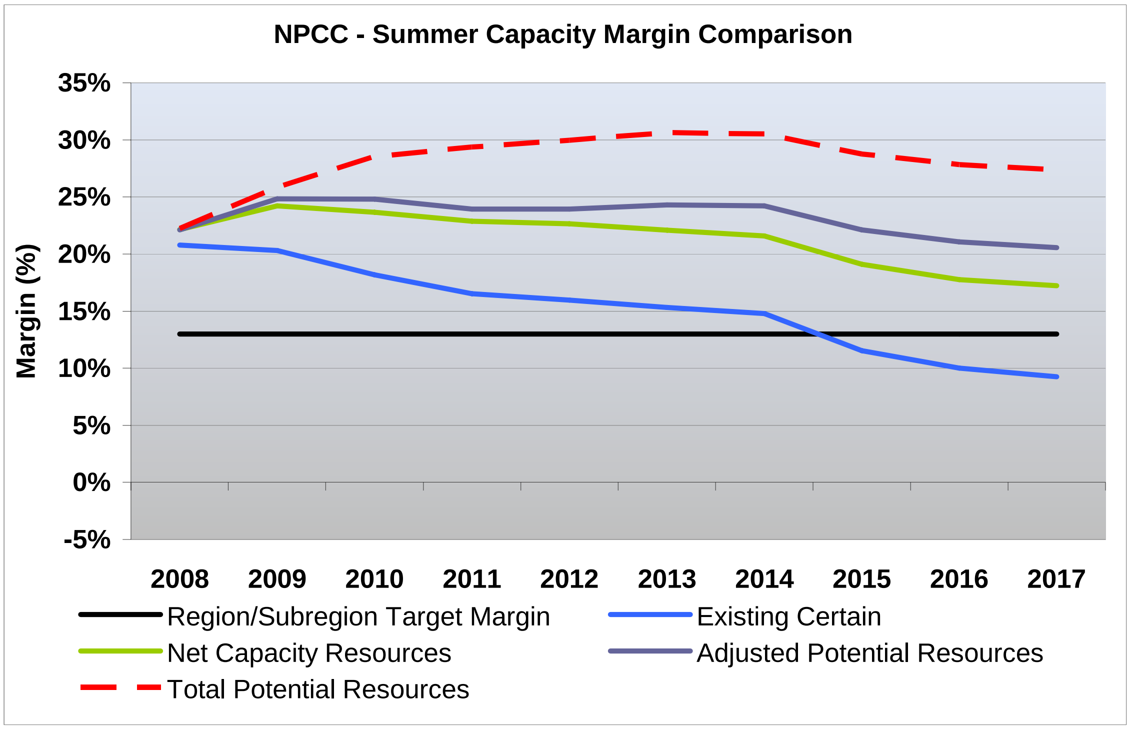
The Maritimes Area has demonstrated compliance with the NPCC reliability criterion of less than 0.1 days of firm load disconnections per year, and the Maritimes Area requires no support from its interconnections to meet the criterion. Reserve levels will vary between 22% and 40%. The most significant change since the 2007 RAS Long-Term Reliability Assessment is a lower demand forecast and demand growth rate currently projected for the Maritimes. Contributing significantly to this lower forecast is a projection of slowing economy, particularly the announced mill closures in the pulp and paper and wood processing sectors, along with limited growth expectations in these sectors due to a high Canadian dollar and rising energy costs.

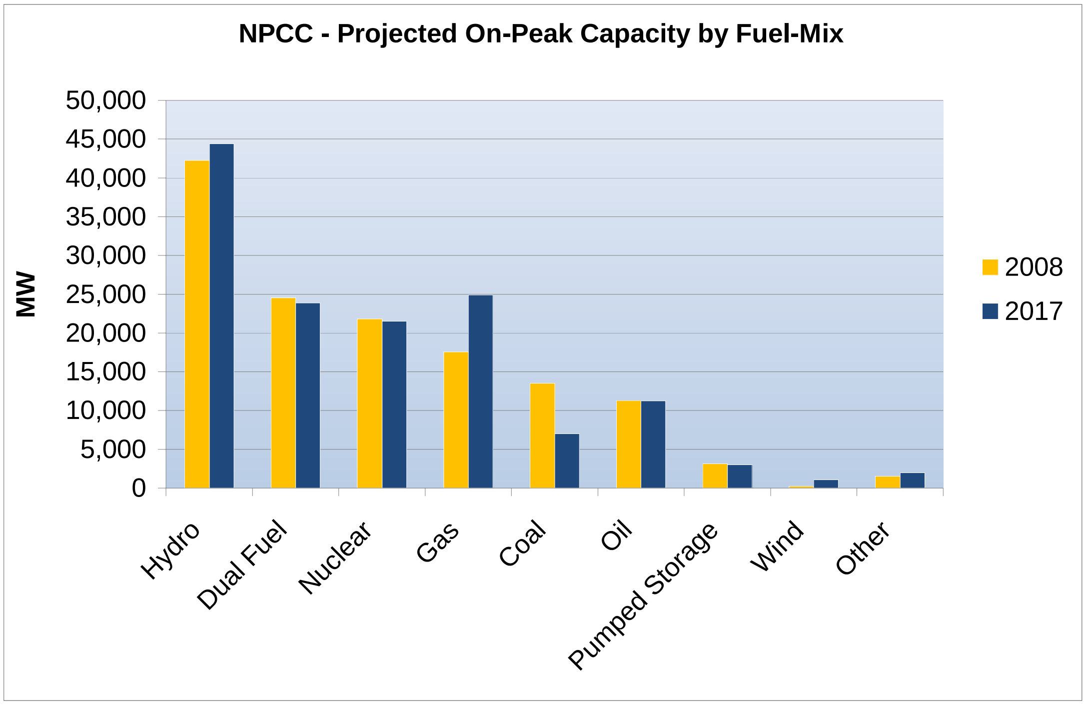
In New England, the capacity needs to meet the NPCC resource adequacy criterion are purchased through annual auctions for a period of time three years in advance of the year of interest. After this primary annual auction, there are annual reconfiguration auctions prior to the commencement year in order to readjust installed capacity purchases and further ensure that adequate capacity will be purchased to meet system needs.

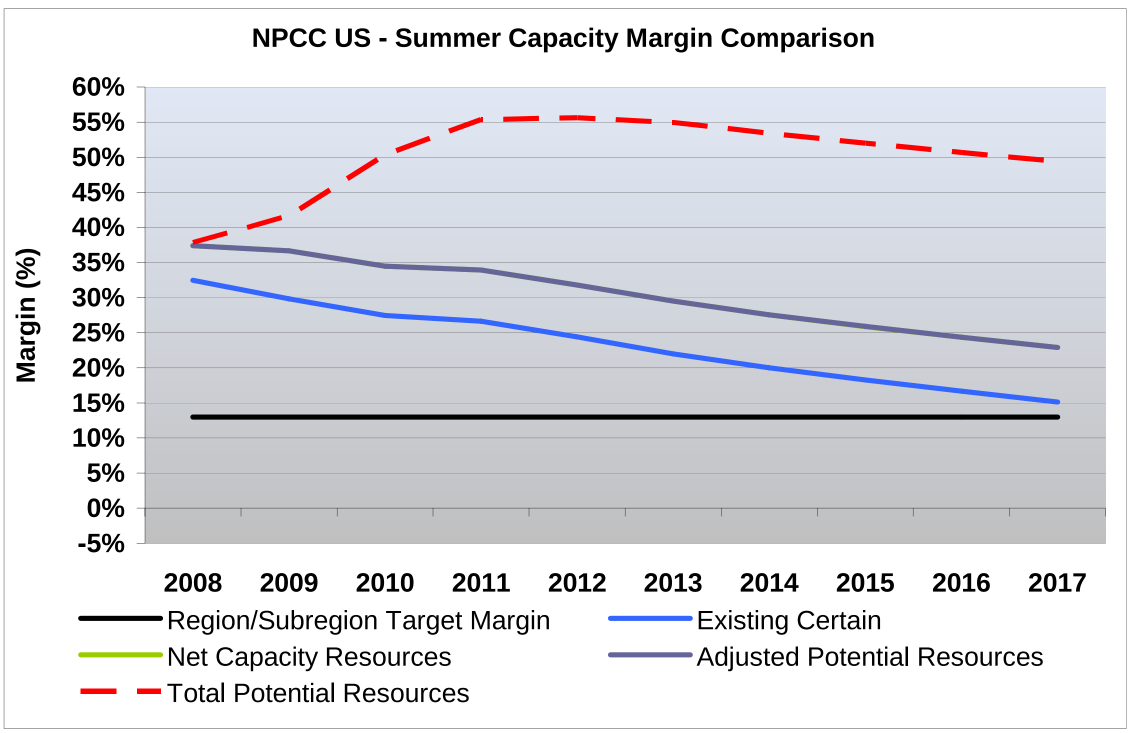
For the New York Area, the New York Independent System Operator conducts an annual Reliability Needs Assessment (RNA) that examines both resource and transmission needs over a ten-year period. Resources totaling approximately 455 MW, as well as transmission upgrades that are under construction or otherwise have met the screening criteria, were included in the base case for the current RNA. This assessment has determined that sufficient statewide resources are available to meet the NPCC LOLE criteria through the year 2011. For 2012, the RNA indicates that sufficient resources will exist if 500 MW were added to New York City (NYC), or if 750 MW were added in the lower Hudson River valley, or if transfer limits into NYC were increased. Beyond 2012, additional resources of approximately 2,750 MW would be needed to meet the criteria through 2017; a majority of those resources would be required for the New York City zone to meet the NYC zonal requirements.

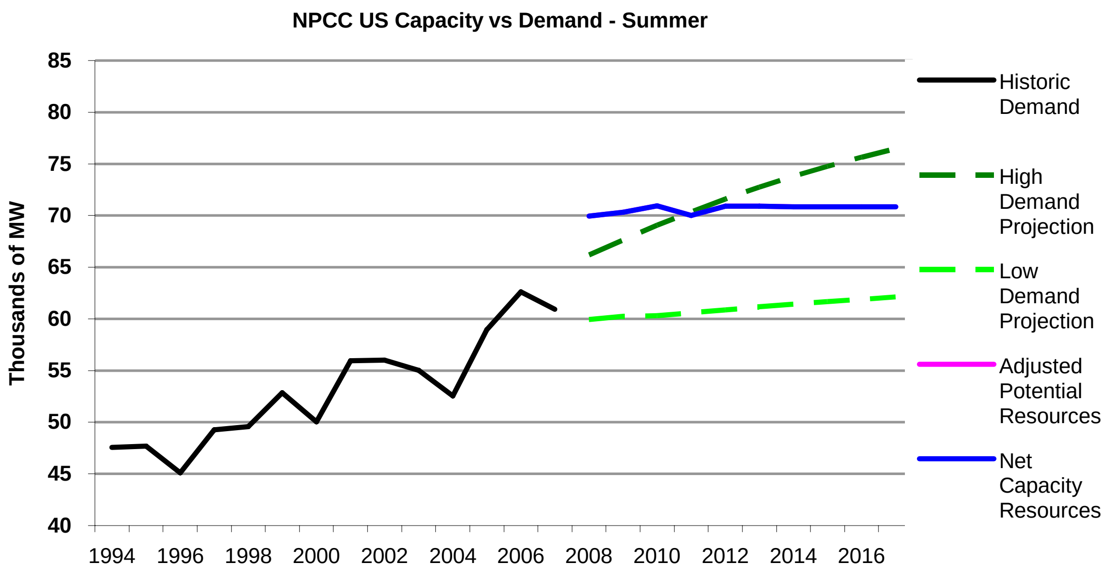
Ontario will eliminate its coal-fired fleet with the retirement of the Nanticoke station, currently scheduled for 2014. Although energy supplies available within Ontario are expected to be adequate overall, energy deficiencies could arise as a result of higher than forecast forced outage situations, prolonged extreme weather conditions and other influencing factors. Interconnection capability and available market and operational measures have been evaluated as sufficient to ensure summer energy demands can be met for a wide variety of conditions.

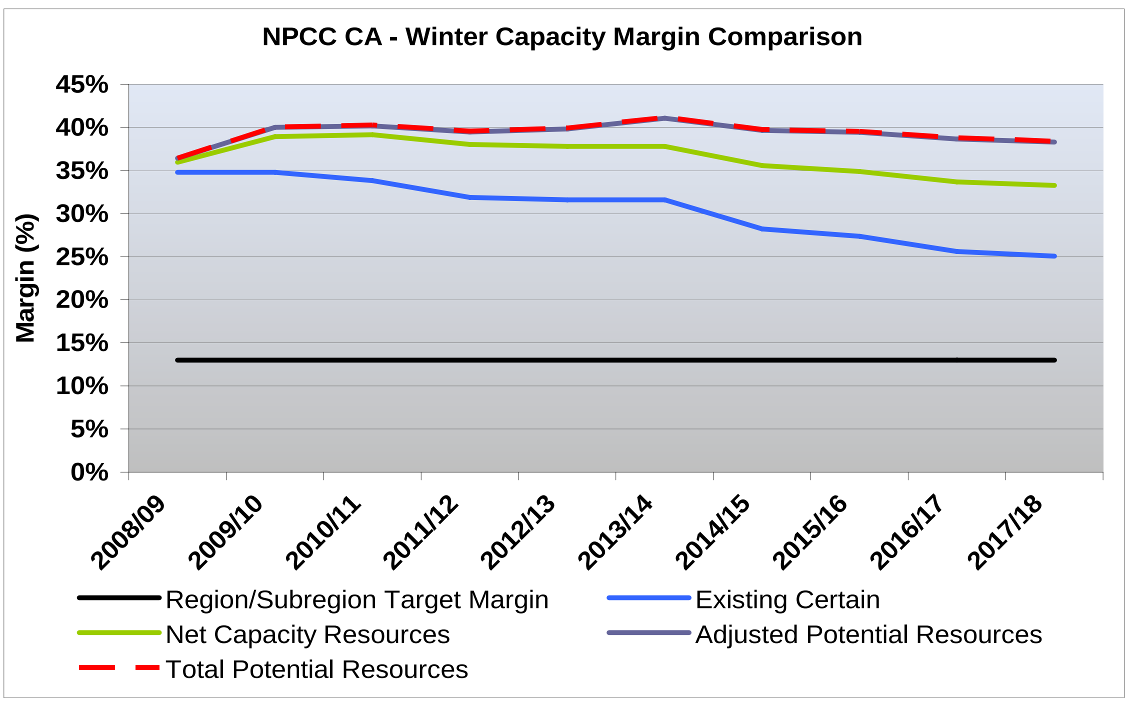
To comply with the NPCC resource adequacy criterion, the Québec Area requires a reserve margin of about 11 % of the peak load for the year of analysis. In Québec, large multi-years water reservoirs allow hydro generation to be available on peak, and non-hydraulic resources account only for a small portion of total resources. Assessments for both NPCC and the Québec Energy Board are conducted annually.

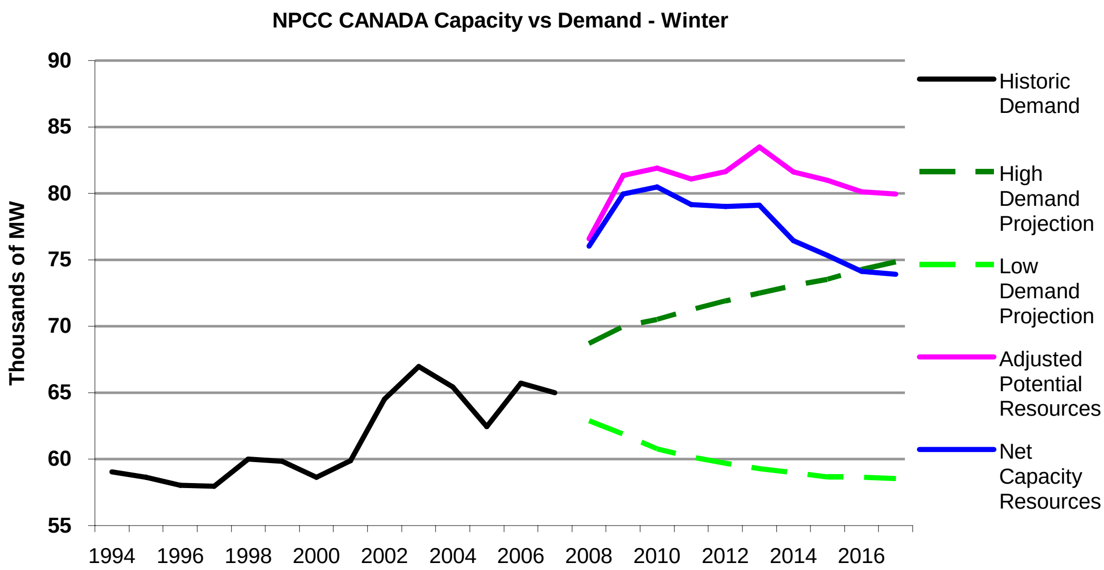


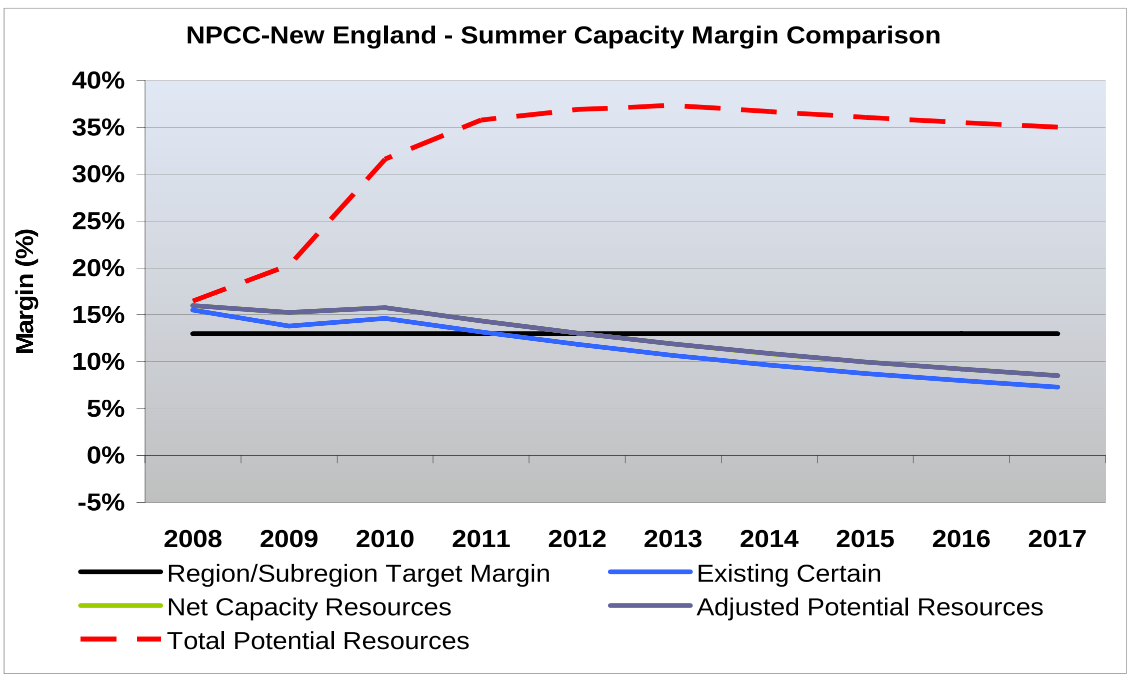

NPCC - Projected On-Peak Capacity by Fuel-Mix
MW
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Hydro
Dual Fuel
Nuclear
Gas
Coal
Oil
Pumped Storage
Wind
Other
2008
2017

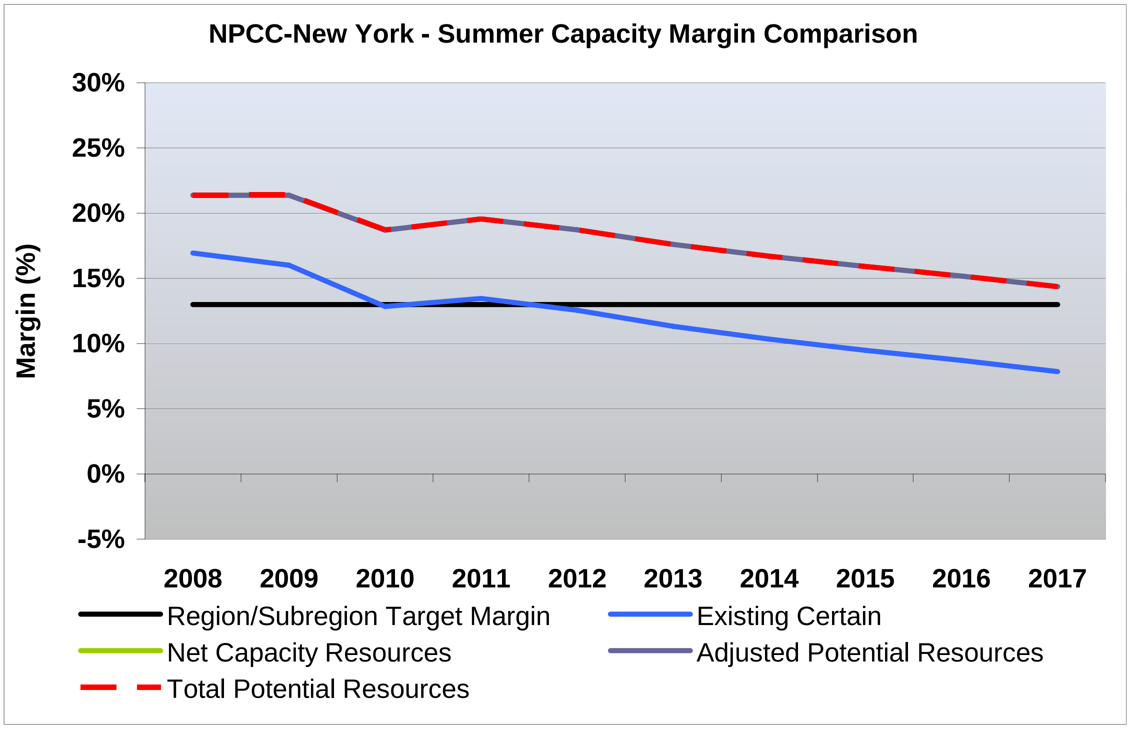

NPCC US - Summer Capacity Margin Comparison
Margin (%)
60%
55%
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

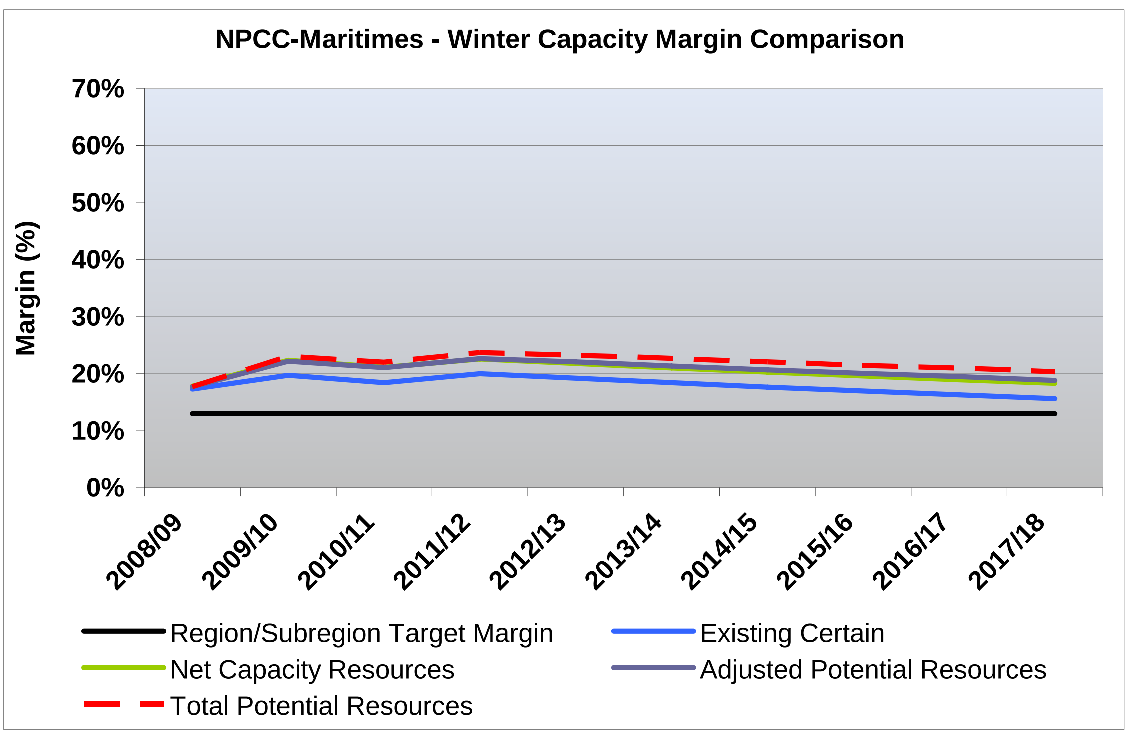

NPCC US Capacity vs Demand - Summer
Thousands of MW
85
80
75
70
65
60
55
50
45
40
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources

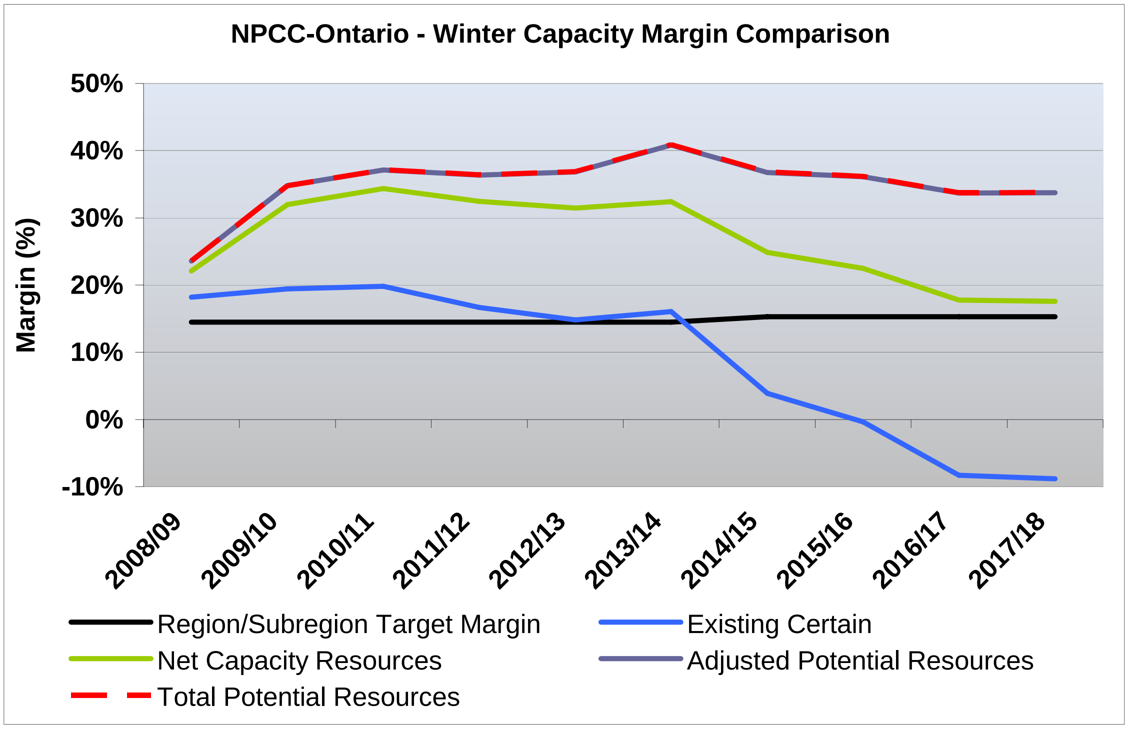

NPCC CA - Winter Capacity Margin Comparison
Margin (%)
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

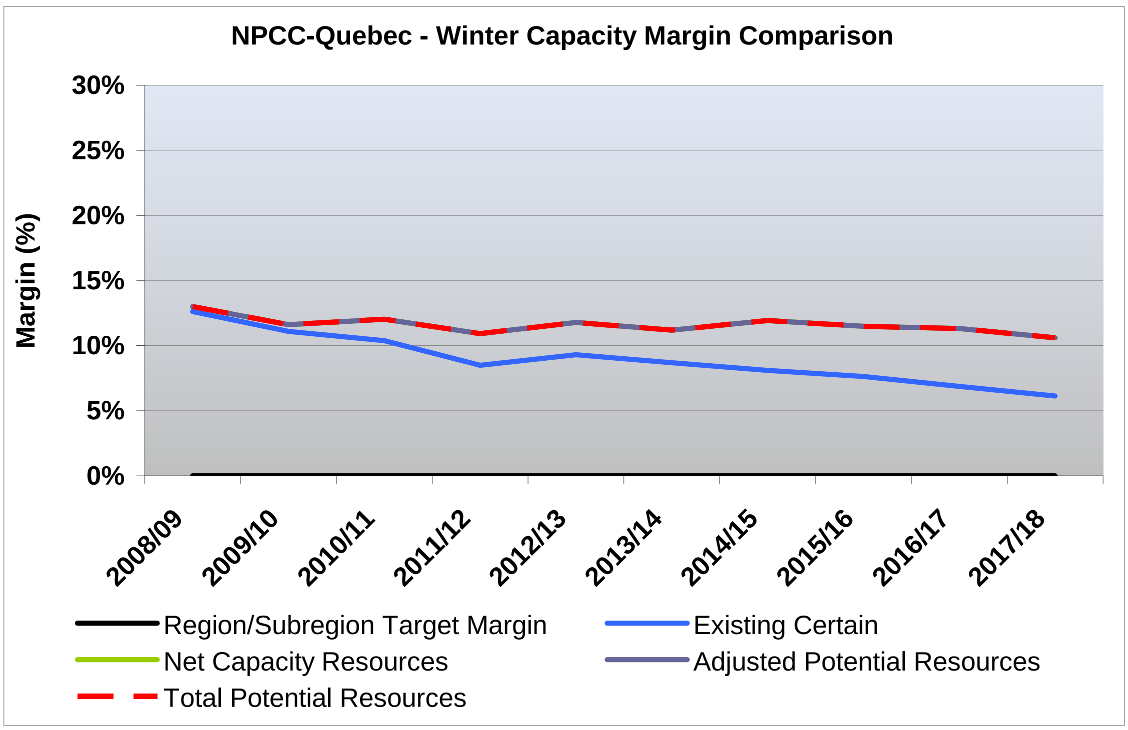

NPCC CANADA Capacity vs Demand - Winter
Thousands of MW
90
85
80
75
70
65
60
55
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources


NPCC-New England - Summer Capacity Margin Comparison
Margin (%)
40%
35%
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


NPCC-New York - Summer Capacity Margin Comparison
30%
25%
20%
15%
10%
5%
0%
-5%
Margin (%)
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


NPCC-Maritimes - Winter Capacity Margin Comparison
70%
60%
50%
40%
30%
20%
10%
0%
Margin (%)
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


NPCC-Ontario - Winter Capacity Margin Comparison
Margin (%)
50%
40%
30%
20%
10%
0%
-10%
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


NPCC-Quebec - Winter Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

NPCC Self-Assessment

Overview

The resource plans of each of the five Areas (subregions) of NPCC meet the NPCC resource adequacy criterion which states that probability of disconnecting firm load shall be not more than once in ten years. Further, the currently planned transmission system over the ten-year period is expected to perform reliably for a range of contingencies and conditions.

The following discussions document the extensive processes in place within NPCC to ensure that both resource and transmission plans remain adequate for the study period.

NPCC Resource Adequacy Assessment Process

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."[145] 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:

- 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 (the 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 Interconnected Power Systems."[146] Section 3.0 of Document A-02 defines the criterion for resource adequacy for each Area as follows:

<u>Resource Adequacy - Design Criteria</u>

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

[145] http://www.npcc.org/documents/regStandards/Guide.aspx
[146] http://www.npcc.org/documents/regStandards/Criteria.aspx

Regions, transmission transfer capabilities, and capacity and/or 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/or shifting load, such as conservation, load management, interruptible loads, dispatchable loads and unmetered, but identifiable small capacity generation.

Document B-08 requires each Area resource assessment to include an evaluation and / or 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.

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

Each Area resource adequacy review will be conducted for a window of five years, and a detailed, "Comprehensive Review," is conducted triennially. For those years when the Comprehensive Review is not required, the Area is charged to continue to evaluate its resource projections on an annual basis. The Area will conduct an "Annual Interim Review" that will reassess the remaining years studied in its most recent Comprehensive Review. Based on the results of the Annual Interim Review, the Area may be asked to advance its next regularly scheduled Comprehensive Review.

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

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."[147] Each Area is required to present an annual transmission review to the TFSS, assessing its planned transmission network four to six years in the future. Depending on the extent of the expected changes to the system studied, the review presented each year by the Area may be one of the following three types:

- Comprehensive Review

  A detailed analysis of the complete bulk power system of the Area is presented every five years at a minimum. The TFSS will charge the Area to conduct such a review more frequently as changes may dictate.

- Intermediate Review

  An Intermediate Review is conducted with the same level of detail as a Comprehensive Review, but, in those instances in which the significant transmission enhancements are confined to a segment of the Area, the review will focus only on that portion of the system. Or, if the changes to the overall system are intermediate in nature, the analysis will focus only on the newly planned facilities.

- Interim Review

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

In the years between Comprehensive Reviews, an Area will annually conduct either an Interim Review, or an Intermediate Review, depending on the extent of the system changes projected for

[147] http://www.npcc.org/documents/regStandards/Guide.aspx

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:

- Steady state performance of the system;
- Dynamic performance of the system;
- Response of the system to selected extreme contingencies; and
- Response of the system to extreme system conditions.

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

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

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

<u>Coordinated Operations</u>

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 Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont,
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 redispatch 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 bulk electric system 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, Guides, and Procedures, establish the fundamental principles of interconnected operations among the NPCC Areas.

NPCC Document A-03, "Emergency Operation Criteria,"[148] 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,"[149] 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.

Various operating Guidelines and Procedures complement the NPCC Criteria by providing the system operator with detailed instructions to address such topics as the depletion of operating reserve, capacity shortfalls, the sharing of operating reserve, line loading relief, declining voltage, measures to contain the spread of an emergency, light load conditions, the rating of generating capability, the consequences of a solar magnetic disturbance, procedures for communications during an emergency and the coordinated restoration of the systems following a partial or total blackout.

Area Assessments

Among the five NPCC Areas, the Maritimes Area and Québec are predominantly winter peaking systems. The Ontario, the New York and the New England Areas are summer peaking systems.

[148] http://www.npcc.org/documents/regStandards/Criteria.aspx
[149] http://www.npcc.org/documents/regStandards/Criteria.aspx

Consequently, the mix of winter and summer peaking areas would make a NPCC-wide comparison of year to year peaks misleading. Comparisons for the individual subregions are below. 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.

Maritimes Area

Introduction

The footprint of the Maritimes Area is comprised of the Canadian 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 radially connected to the New Brunswick power system. The Maritimes Area is a winter peaking region.

On October 1, 2004, New Brunswick's Electricity Act restructured the electric utility industry in New Brunswick (NB) 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 (NS), 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.

Demand

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 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 eight-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 use of electrical energy.

The NSPI load forecast for Nova Scotia is based on 30-year historical climate normalization for the major load centers, 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 2008/09 peak demand forecast, representing the summation of the forecasts of each Maritimes Area jurisdiction, is 5,705 MW, 269 MW lower than last year. The forecast average annual peak demand growth rate is 0.9% over the next ten years, and this is lower than the 1.7% 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 due to a high Canadian dollar and rising energy costs.

Monthly peak forecasts for the Maritimes Area are summations of the individual jurisdiction forecasts. For Area studies, the individual forecasts are combined using the load shape of each jurisdiction.

The only demand response program currently used in the Maritimes Area is interruptible demand. For 2008/09, the interruptible demand forecast for the peak month is 485 MW, which represents 8.5% of the peak demand 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.

Generation

The Maritimes Area capacity resources in 2008/09 amount to 6,312 MW of Existing Certain capacity resources, 663 MW of Existing Uncertain capacity resources, 39 MW of Planned capacity resources, and 0 MW of Proposed capacity resources. The largest portion of the Existing Uncertain capacity resources is 558 MW of inoperable capacity at the Point Lepreau nuclear station due to an 18-month refurbishment between April 2008 and October 2009.

By 2009/10, the Planned capacity resources increase to 225 MW, consisting of 100 MW of incremental nuclear capability from the Point Lepreau refurbishment, and 125 MW of on-peak wind capacity. By 2017/18, the Proposed capacity resources increase to 272 MW, of which 196 MW is on-peak wind capacity.

In 2008/09, the wind generation expected on-peak represents 61 MW of the Existing Certain capacity resources, 66 MW of the Existing Uncertain capacity resources, and 39 MW of the Planned capacity resources.

In 2008/09, biomass capacity represents 153 MW of Existing Certain capacity resources, and 5 MW of Existing Uncertain capacity resources. There is no Planned or Proposed biomass capacity for the Maritimes during the study period.

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.

Purchases and Sales on Peak

The capacity purchase for the Maritimes is a firm 200 MW purchase from Hydro Quebec during the 2008/09 winter peak season.

The firm capacity purchase from Hydro Quebec is not tied to a specific generator. The purchase is backed by a transmission reservation.

The capacity purchase from Hydro Quebec is not an LDC.

For the period 2008 through October 2011, there is a firm capacity sale of 198 MW from the Maritimes to Hydro Quebec. This sale is tied to two 99 MW oil combustion turbines at Millbank, NB. This sale is also backed by a transmission reservation.

For 2008, there are a total of non-firm capacity sales of 11 MW from the Maritimes to New England. These non-firm capacity sales rise to 91 MW between 2009 and 2017. These capacity sales are tied to renewable energy projects in the Maritimes, and are not backed by transmission reservations.

None of the capacity sales from the Maritimes are LDCs.

The Maritimes Area participates in a regional reserve sharing program with New England, New York, and Ontario for 100 MW of ten-minute reserve. This reserve is counted as 25% spinning and 75% supplemental.

Fuel

Due to the diversity of the Maritimes Area fuel supply mix, its relatively low reliance on natural gas, and its fuel storage facilities, the potential impact of fuel supply and/or delivery interruptions in the Maritimes Area is very low, and thus it is not explicitly modeled in resource adequacy assessments.

The percentage of natural gas in the Maritimes is less than 8%, and the percentage of coal-fired generation is about 27%.

Transmission

Currently, the only new bulk power system transmission anticipated to be in-service during the ten year study period is a 103-mile, 345 kV line between Coleson Cove, NB and Salisbury, NB. The expected in-service date in sometime between 2009 and 2016.

There are no transformer additions to the Maritimes bulk power system within this ten year study period.

Operational Issues

There are no significant anticipated generating unit outages, variable resource, transmission additions or temporary operating measures that are anticipated to impact the reliability of the Maritimes during the next ten years.

There are no environmental or regulatory restrictions that are anticipated to impact the reliability of the Maritimes during the next ten years.

Reliability Assessment Analysis

The Maritimes uses a reserve criterion of 20% for planning purposes and it was shown in the 2007 Maritimes Comprehensive Review of Resource Adequacy[150] that adherence to this criterion complies with the NPCC reliability criterion. The 20% reserve criterion is met in all ten years of the study period, with a minimum reserve of 22% occurring in 2008/09 due to the refurbishment of Point Lepreau.

The Maritimes reserve criterion of 20% is set to a level which complies with the NPCC reliability criterion.

Except for the 200 MW firm capacity purchase from Hydro Quebec during the peak winter months of 2008/09, all of the resources used to meet the reserve margin criterion are internal to the Maritimes.

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,”[151] it was shown that 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/yr for the base load forecast with load forecast uncertainty. The Maritimes Area requires no support from its interconnections to meet the NPCC reliability criterion for all

[150] http://www.npcc.org/documents/reviews/Resource.aspx
[151] http://www.npcc.org/documents/reviews/Resource.aspx

years of the 2008-2012 study period. The Maritimes Area is also shown to adhere to its own 20% reserve planning criterion in all years for the base load forecast, with reserve levels varying between 22% and 40%.

There is no difference in how the Maritimes treats short-term (i.e. 1-5 years) and long-term (i.e. 6-10 years) reserve requirements.

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 due to a high Canadian dollar and rising energy costs. With this lower demand comes higher forecast reserve margins, and therefore less need to plan for any major new capacity in the Maritimes.

In its 2007 Maritimes "Comprehensive Review of Resource Adequacy," [152] 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% reserve criterion in all cases with no more than 35 MW of necessary interconnection support. This level of interconnection support represents only 2.1% of the Maritimes Area tie benefits capability.

As mentioned in part vii), the 2007 Maritimes Comprehensive Review of Resource Adequacy demonstrated compliance with the NPCC reliability criterion for the high load growth scenario.

Wind project capacity for the Maritimes is modeled based upon results from the September 21, 2005 NBSO report "Maritimes Wind Integration Study".[153] This report showed that the effective capacity from wind projects, and their contribution to Loss of Load Expectation 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.

There are no potential unit retirements having significant impact on the reliability of the Maritimes.

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 that generation is sufficiently integrated with load.

The Maritimes is studying an interconnection request from Newfoundland and Labrador Hydro involving an HVDC interconnection between Newfoundland and the Maritimes that would transmit up to 740 MW from the Lower Churchill hydro project to either New Brunswick or

[152] http://www.npcc.org/documents/reviews/Resource.aspx
[153] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf

Nova Scotia, and then on down to New England. The target in-service date is January 1, 2015 but due to its uncertainty it hasn't been included as a proposed project.

Currently, there are no specific deliverability problems in the Maritimes with the current portfolio of wind generation. Future proposed wind projects concentrated in certain areas may cause some congestion issues, and those issues are addressed in the System Impact Studies for those projects.

System Impact Studies are mandatory for new generation interconnections, and may be required for changes/additions to the transmission grid. There are no anticipated stability issues impacting the reliability of the Maritimes during the study period.

Under normal conditions, the Maritimes grid is to be designed and operated within a plus or minus 5% of nominal voltage. Both synchronous generators as well as wind projects have minimum voltage support requirements in the form of leading and lagging power factor capability.

Generators in the Maritimes must not cause a voltage dip greater than 3% during start-up or shutdown. There are no known reactive power-limited areas in the Maritimes Area. 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. Nuclear capacity will be increased by 100 MW due to the refurbishment of Point Lepreau.

Bulk power system reliability has increased significantly with the commissioning of the second 345 kV interconnection between New Brunswick and New England in December 2007.

There are no reliability impacts to any specific aging infrastructure in the Maritimes area. The aging of the Point Lepreau nuclear station is being addressed through its refurbishment from April 2008 to October 2009.

The Maritimes does not have any guidelines for on-site, spare generator step-up (GSU) or autotransformers.

New England

ISO New England's reference case forecast is the 50/50 forecast (50% 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 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The reference demand forecast is based on the reference economic forecast, which reflects the economic conditions that “most likely” would occur.

This year’s summer peak forecast ten-year compound annual average growth rate has decreased to 1.2 percent from 1.7 percent, resulting in generally lower summer peak forecasts when compared with the 2007 long-term forecast. The key factor leading to the lower forecasts is a long-run forecast of lower personal income, which is an economic driver in the energy and peak load models.

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

It is expected that 1,820[154] MW of demand resources will be available in summer 2008. These include resources in ISO New England’s Real-Time 30-minute, Real-Time 2-Hour, and Profiled Demand Response programs, which are instructed to interrupt their consumption during specific actions of Operating Procedure No. 4 (OP 4), *Action During a Capacity Deficiency*. 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 167 MW of energy efficiency. The 1,820 MW of demand resources is expected to grow to 2,278 MW by 2010 because that is the amount of demand resources that has cleared ISO New England’s first Forward Capacity Auction (FCA), for the 2010-2011 commitment period.

The 2,278 MW of demand resources that cleared the first FCA include new energy efficiency programs totaling 612 MW. The energy efficiency programs are also considered capacity resources in the New England capacity market. Under FCM, energy efficiency can be included in the category of on-peak demand resources[155], which includes installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy consumed during on-peak hours. 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 date along with a project completion schedule. In addition, the new demand resource submits a Measurement and Verification (M&V) Plan, which must be approved by the ISO. The project sponsor is required to submit certification that the project complies with their ISO-approved M&V Plan. The ISO has the right to audit the records, data, or actual installations to ensure that the energy efficiency projects are providing the load reduction promised. The ISO tracks the project against their submitted schedule, thereby taking a proactive role in monitoring the progress of these resources to ensure that they are ready to reduce demand by the start of the FCM commitment period.

[154] This value is 137 MW higher than the demand resources assumed for the 2008 NERC RAS Summer Assessment due to updated information.

[155] The rules addressing the treatment of demand resources in the Forward Capacity Market may be found in Section III.13.1.4 of ISO New England’s *Market Rule 1, Standard Market Design*, located at http://www.iso-ne.com/regulatory/tariff/sect_3/v8-7-1-08_mr1_sect_13-14.pdf

In addition to reliability-based programs, ISO-NE administers a voluntary price-response program where load interrupts based on the price of energy. As of March 31, 2008, there were approximately 97 MW enrolled in the price response program. These programs are not counted as capacity resources since their interruption is voluntary.

ISO New England addresses peak demand uncertainty in two ways:

- Weather – annual peak load distribution forecasts are made based on 37 years of historical weather which includes the reference forecast (50% chance of being exceeded), and extreme forecast (10% chance of being exceeded);[156]
- Economics – alternative forecasts are made using high and low economic scenarios.

ISO New England reviews the summer conditions of the study period using the annual extreme, 90/10 peak demand based on the reference economic forecast.

Resources

The ISO New England Balancing Authority capacity resources amount to 32,933[157] MW in 2008. That includes 30,892 MW of Existing Certain generating capacity, 1,820 MW of demand response resources, and 58 MW of net firm purchases and sales. Also included in the total capacity resources is 181 MW of Planned generating capacity, which is expected to become commercial by summer 2008. The total new generation expected to be in service by 2010 amounts to 427 MW. In addition to the Planned capacity, ISO New England has a total of 13,028 MW of Proposed projects in its Generator Interconnection Queue, with in-service dates ranging from 2008 to 2014.

Approximately four MW of the Existing Certain capacity is wind generation expected on peak. The total nameplate capability of those wind facilities is 11 MW. The Planned capacity includes 43 MW (124 MW nameplate) of new wind capacity, which is expected to be in service by summer 2009. Proposed wind capacity in New England amounts to 1,713 MW based on nameplate ratings, with target in-service dates of 2008 through 2011.

Also included in the Existing Certain capacity is 765 MW of variable hydro resources expected on peak.

Biomass capacity in the Existing Certain category totals 888 MW. Two additional Planned biomass facilities totaling 25 MW are expected to be in operation by summer 2009. A total of 515 MW of biomass capacity is Proposed for installation in New England with target in-service dates of 2009 through 2014.

ISO-NE's capacity margin calculations include Planned capacity resources that are expected to begin commercial operation by the end of 2008. This information is based on either the date

[156] On an annual basis, the 50/50 reference peak has a 50% chance of being exceeded, and the 90/10 extreme peak has a 10% chance of being exceeded.

[157] Due to differences in assumptions, the amount of existing and planned capacity in summer 2008 is different from that published in ISO New England's 2008-2017 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report).

specified in a signed Interconnection Agreement, or discussions with ISO-NE Customer Services indicating that the project is nearing completion and is preparing to become an ISO generator asset. Also included in the Planned capacity resources are new projects that have obligations in the ISO-NE Forward Capacity Market in 2010-2011.

Purchases and Sales on Peak

Firm purchases amount to approximately 400 MW through 2012 and then decrease to 334 MW in 2013 – 2014. Only firm, Installed Capacity (ICAP) purchases that are known in advance are included as capacity. A total of 934 MW of import capacity resources cleared in the first Forward Capacity Auction for the 2010-2011 commitment period. Although those are one-year contracts, they were assumed to extend through the end of the study period. If these particular imports do not clear in future FCM commitment periods, the capacity will be replaced by generator resources or other imports.

The entire amount of ICAP purchases is backed by firm contracts for generation, and the imports under the Forward Capacity Market are import capacity resources with an obligation for the 2010-2011 Capacity Commitment Period. Although there is no requirement for those purchases to have firm transmission service, it is specified that deliverability of firm purchases must meet the New England delivery requirement and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of firm energy, but the market participant bears the associated risk of market penalties if it chooses to use non-firm transmission.

The 310 MW purchase from Hydro-Québec is a Liquidated Damage Contract (LDC) that is not a "make-whole" contract. The 91 MW purchase from New York is not an LDC.

For the period 2008 through 2009, ISO New England is aware of a firm capacity sale to New York (Long Island) of 343 MW, anticipated to be delivered via the Cross Sound Cable. 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.

This sale is backed by a firm contract for generation, but because the power has to go through the Connecticut import constrained interface, and there is no firm transmission arrangement, it can be cut earlier than non-recallable exports in the case of a transmission import constraint into Connecticut.

The sale across the Cross Sound Cable is based on a make-whole contract.

For resource adequacy studies, ISO New England assumes 2,000 MW of emergency assistance is available during 2008 and 2009, and 1,860 MW of emergency assistance from 2010 through 2018. This assistance is also referred to as tie-line benefits that are available from other areas within the NPCC region, and is about 50% of New England's total import capability. ISO New England also participates in a regional reserve sharing group with NPCC, and has a shared activation of reserves agreement with New York for up to 300 MW.

Fuel

Generation in New England is fueled primarily by natural gas (42.2%), followed by nuclear generation (28.3%), coal (15.1%), non-hydro renewables (6.0%), hydro (4.9%), oil (2.2%) and pumped storage (1.3%). Fuel supply vulnerability is not a concern for any of the fuels other than natural gas. Hydro capacity is not a concern because the New England region seldom experiences droughts, and because such resources make up a small percentage of the New England generation. Oil-fired plants, which also are only a small portion of generation in New England, typically have multiple days of fuel storage.

Coal is primarily imported via ocean-going transport and is procured through a combination of spot-market, medium- and long-term contracts. Aside from weather-related shipping delays, coal can be readily stored and stockpiled within the region. There are no coal supply or delivery problems anticipated for New England for 2008 and beyond.

During the winter, New England's natural gas-fired generators continue to compete with the core natural gas demand (i.e., for space heating) for gas supply and finite transportation infrastructure. During winter peak load periods, regional natural gas pipeline capacity may not be sufficient to serve the coincident demands from both the gas and electricity sectors. During extreme cold winter weather, when the demand for natural gas and electricity peak coincidently, ISO-NE has developed a cold weather operating procedure that can be implemented to help mitigate the loss of operable generating capacity. ISO-NE has also implemented market incentives, such as those provided by the Forward Capacity Market, that encourage the conversion of single-fuel, gas-only units to dual-fuel capability in addition to promoting the procurement of firm gas supply and transportation contracts.

The ongoing concern over the interruption of regional natural gas supply is mitigated through ISO New England's regular monitoring of the gas supply situation, and communications with the natural gas sector. An Energy Emergency operating procedure can be implemented during any time of the year, to help mitigate the operational impacts of both short and long-term fuel supply shortages.

One area of potential concern is with natural gas interchangeability. Two new Liquefied Natural Gas (LNG) import terminals (one onshore and one offshore) will soon be commercialized within the region. ISO-NE has and will continue to monitor the development of and revisions to natural gas quality standards within the regional gas pipelines tariffs. Questions regarding the potential impacts from compositional variability within natural gas streams have been raised by gas-fired generators. ISO-NE will continue to monitor these developments on both a regional and national scale.

Transmission

ISO New England's 2008 Regional System Plan[158] will identify the region's needed transmission improvements for this period. The New England region currently has over 250 transmission projects and components[159] in various stages of planning, construction, and implementation.

Operational Issues

There are no significant anticipated generating unit outages, variable resource, transmission additions or temporary operating measures that are anticipated to impact reliability during the next ten years. Planned outages and the addition of new facilities is coordinated by the ISO and must pass through a rigorous operational review to ensure continued system reliability before allowing such system outages or additions to occur.

During extremely hot days and low river flow conditions, there may be environmental restrictions on generating units due to water discharge temperatures. Such conditions could result in capacity reductions ranging from 150 MW to 200 MW. These reductions are reflected in the ISO's forced outage assumptions. The ISO monitors the situation and expects adequate resources to cover such forced outages or generator reductions.

Reliability Assessment Analysis

The calculated installed capacity margins based on generator and demand resources is 17 percent of the reference load forecast in 2008, and will be 15 percent in 2009 assuming no changes in capacity. In 2010, the margin increases to 18 percent. The margin in 2010 reflects the resources that have obligations to serve the capacity needs of the ISO New England Balancing Authority area resulting from ISO New England's first Forward Capacity Auction. It was assumed that resources with obligations for that year will remain in place through the end of the study period. Without any assumed additional resources, the capacity margin declines after 2010 to 10 percent by 2017. New England does not have a particular capacity margin requirement; rather it plans resources to meet the once in ten years loss of load expectation resource planning reliability criterion. The capacity needs to meet this criterion are purchased through annual auctions three years in advance of the year of interest. After this primary annual auction, there are annual reconfiguration auctions prior to the commencement year in order to readjust installed capacity purchases and ensure that adequate capacity will be purchased to meet system needs. Therefore, ISO New England does not expect to face any installed capacity shortages in the future. For reference purposes, the annual average percent capacity needed to meet the resource adequacy planning criterion based on a forecast of representative future installed capacity requirements is approximately 15 percent.

To develop installed capacity requirements to meet the once in 10 years disconnection of firm load resource planning reliability criterion, ISO New England takes into account the random behavior of load and resources in a power system, and the potential load and capacity relief

[158] Summaries of transmission studies and projects can be found in the ISO New England 2008 Regional System Plan (final report expected to be posted by the end of 2008) at www.iso-ne.com/trans/rsp/index.html
[159] The project listing can be found on the ISO New England web site at www.iso-ne.com/trans/rsp/index.html

obtainable through the use of ISO-NE Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP 4).

The amount of internal generating and demand resource capacity assumed available to meet the installed capacity requirement is 32,586 MW in 2008 and 32,965 in 2009, increasing to 33,419 for the remainder of the study period to reflect the resources procured for the 2010-2011 FCM. The total capacity to serve load, including net purchases and sales, is 32,644 MW in 2008 and 34,077 in 2010.

The amount of resources external to New England reflects capacity purchases of 401 MW per year in 2008 and 2009, increasing to 934 MW in 2010.

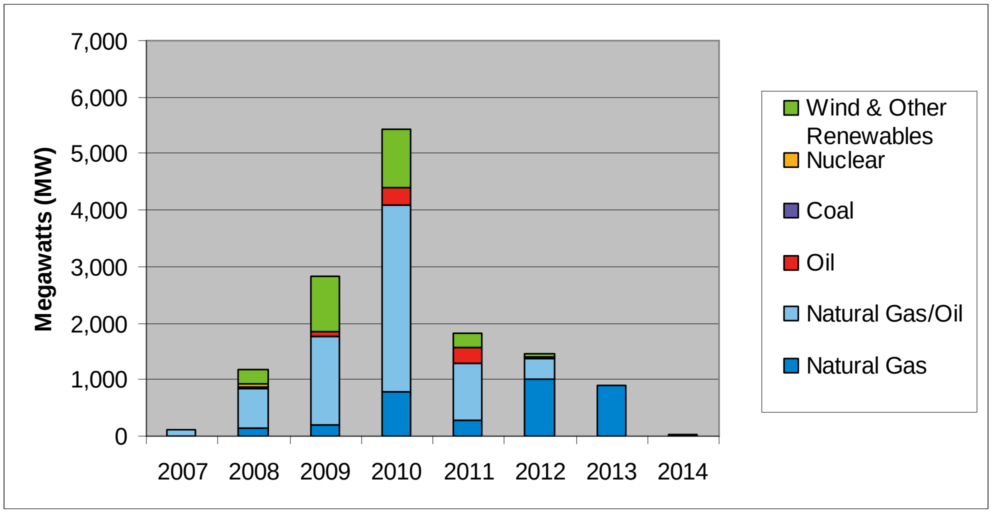
ISO New England conducts resource adequacy studies to identify the resources needed to meet the NPCC resource adequacy criterion of once in ten years loss of load expectation. The ISO conducts such studies on an annual basis for the regional system plan (RSP). The study conducted for RSP08 shows that if there are no changes in the current generator and demand resource capacity of 32,644 MW, the New England system will need an additional 565 MW of physical capacity in 2012 to meet the resource adequacy planning criterion. By 2017, the additional capacity required will be 2,414 MW. However, 34,077 MW of generating, demand and import resources cleared in the first Forward Capacity Auction for 2010. Assuming that amount is in service and does not change, New England will need additional resources only by 2015.[160] As shown in the table below, under such assumed load and resource conditions, an additional 360 MW would be needed in 2015, increasing to a total of 981 MW by 2017.

The following table shows ISO New England's Installed Capacity Requirements and additional physical capacity resources possibly needed to meet the resources adequacy criterion.

Year	Forecast 50/50 Peak	Representative Future Net ICAP Requirement	Assumed Existing ICAP	Cumulative Additional Resources Needed Based on Existing ICAP	Amount of ICAP that Cleared in the First FCA	Cumulative Additional Resources Needed Based on the FCA Cleared Resources
2008	27,970	30,960	32,644	-		N/A
2009	28,480	31,613	32,644	-		N/A
2010	28,995	32,305	32,644	-	34,077	-
2011	29,405	32,671	32,644	-	34,077	-
2012	29,820	33,209	32,644	565	34,077	-
2013	30,190	33,702	32,644	1,058	34,077	-
2014	30,510	34,084	32,644	1,440	34,077	7
2015	30,790	34,437	32,644	1,793	34,077	360
2016	31,035	34,781	32,644	2,137	34,077	704
2017	31,250	35,058	32,644	2,414	34,077	981

[160] The 7 MW of need shown for 2014 may be approximated as 0

ISO New England has 13,669 MW of projects in its Generator Interconnection Queue. These resources could help meet New England's future Forward Capacity Auction needs. Historically, approximately 30 to 35 percent of projects in the Queue have gone into commercial operation. The capacity of projects in the Queue, by fuel type and in-service date, is illustrated in the chart below.



There is no difference in how ISO New England treats short-term (i.e. 1-5 years) and long-term (i.e. 6-10 years) capacity margin requirements.

The amount of demand resources (DR) has increased significantly since last year's assessment, with the DR projection for 2008 more than doubling from 828 MW to 1,820 MW. New generation totaling approximately 427 MW is assumed to be in service by the 2010-2011 FCM. This is nearly 350 MW higher than last year's projection for new generation.

ISO New England uses operating procedures to address real-time problems with resource adequacy. Actual resource unavailability due to fuel interruptions or other conditions are used to formulate resource availability assumptions for long-range resource adequacy studies conducted on an annual basis.

ISO New England also conducted an operable capacity analysis based on the 90/10 peak-load forecast for its 2008 Regional System Plan. That analysis is shown in the table below. 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 New England purchases the exact amount of resources to meet the installed capacity requirements. A total of 1,800 MW of operating reserves are assumed for 2009, which increases to 2,000 MW for all other years to reflect an assumed increase in import capability over the Hydro-Quebec Phase II interconnection from 1,200 MW to 1,400 MW. A total of 2,100 MW of supply-side resource outages were assumed on the basis of 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.

Capacity Situation (Summer MW)	2009	2010	2011	2012	2013	2014	2015	2016	2017
Load (90/10 forecast)	30,475	31,015	31,525	31,995	32,410	32,775	33,085	33,360	33,595
Operating reserves	1,800	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total requirement	32,275	33,015	33,525	33,995	34,410	34,775	35,085	35,360	35,595
Capacity	32,644	32,305	32,671	33,209	33,702	34,084	34,437	34,781	35,058
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total net capacity	30,544	30,205	30,571	31,109	31,602	31,984	32,337	32,681	32,958
Operable capacity margin	-1,731	-2,810	-2,954	-2,886	-2,808	-2,791	-2,748	-2,679	-2,637

As shown in the above table, negative operable capacity margins ranging from approximately -1,730 MW to -2,950 MW were calculated for the period 2009 through 2017. When New England is short of operable capacity, ISO New England will implement Operating Procedure No. 4 — *Action During a Capacity Deficiency*[161] (OP 4). OP 4 is designed to provide additional generation and load relief needed to balance electric demand and supply while striving to maintain appropriate operating reserves. Capacity available under OP 4 includes voltage reduction and emergency assistance from neighboring balancing authorities. For the purposes of the ISO New England operable capacity studies (not reflected in the table above), 2,000 MW of emergency assistance is assumed to be available through 2009. That number changes to 1,860 MW beginning in 2010.

ISO New England does not consider any energy-only, existing-uncertain wind or transmission-limited resources in its resource adequacy assessment.

ISO New England is not aware of any future unit retirements, and does not make projections about potential retirements.

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

Currently, New England does not have interconnection requests for new resources in the 6-10 year time frame.

The New England methods for Installed Capacity Requirement analysis and the Forward Capacity Market are designed to recognize transmission constraints and to procure generation that is incrementally useful to serve new load.

[161] Operating Procedure No. 4 may be found on ISO-NE's website at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

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.

The impact of new generator interconnections or changes/additions to transmission system topology on transient performance and voltage or reactive performance of the bulk power system is routinely analyzed and plans are developed to mitigate concerns as part of the interconnection process. Operating studies to develop operating guides are generally performed under light load conditions to assess the impact on transient performance and under both peak and light load conditions to assess the impact on voltage/reactive performance. Therefore each and every change to the generation/transmission system is either implicitly or explicitly evaluated from a transient and voltage/reactive perspective. There is nothing during the study period which would introduce any new concerns in these areas.

New England has specific criteria to manage minimum dynamic reactive reserve requirements. ISO Op**er**ating Procedure (OP #17) defines acceptable Load Power Factor requirements for various subregions within New England. The procedure is designed to ensure adequate reactive resources are available in the subregion by managing the reactive demand. Furthermore, when transfer limits are developed for voltage or reactive constrained subregions, the ISO will develop detailed operating guides that cover all relevant system conditions to ensure reliable operation of the bulk power system. In determining the acceptable transfer limits, a 100 MW reserve margin is typically added to each limit to ensure that adequate reactive reserves are maintained. In some areas, such as Boston and Connecticut, where specific reactive compensation concerns exist, specific operating guides have been developed to ensure that the areas are operated reliably.

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

There are no known reactive power-limited areas in the New England transmission system. Transmission planning studies have ensured that adequate reactive resources are provided throughout New England. For 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. New England, in creating transfer limits based on the dynamic performance of the system, does apply a 100 MW margin to transfer limits.

At this time, there are no plans to install more 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 that 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.

ISO New England addresses the loss of a major import path by covering the possible loss with operating reserve requirement.

ISO New England's Operating Procedures 21 – *Action During an Energy Emergency* (OP 21) addresses energy emergencies, which may occur as a result of sustained national or regional shortages in fuel availability or deliverability to the New England region's generation resources. Because fuel shortages may impact the New England 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. OP 21 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.

The New England area is currently not experiencing a drought.

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,[162] ensure conformance with TPL-001 through TPL-004.
New England already has a number of installations of new technology. These include two STATCOMs, voltage source converter based HVDC, variable reactors, a short section of gas-insulated transmission line (GITL) and D-VAR. Presently there are no specific plans for the additional use of such technologies in future projects, but they are always under consideration as tools for upcoming 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 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.

New England does not have any guidelines for on-site, spare generator step-up (GSU) or autotransformers. New England has been having numerous discussions on possible policies to address these concerns with respect to autotransformers. In addition, some of New England's

[162] The project listing can be found on the ISO New England web site at www.iso-ne.com/trans/rsp/index.html

Transmission Owners have joined on to the EEI initiated Spare Transformer Equipment Program.

Other region-specific issues that were not mentioned above

ISO New England and the broader industry face challenges associated with retirement of a seasoned, technical workforce coupled with a shrinking pool of available talent. To address these issues, ISO New England has developed a comprehensive Succession Management Program designed to identify highest potential employees and build Retention Plans for them. In additions, to ensure ISO New England continues to attract and retain the best talent the industry has to offer, ISO-NE has adjusted compensation for engineering professionals, and is in the process of developing a technical career path for its Information Technology professionals to offer them the ability to continue career advancement. ISO New England has also expanded its recruiting strategy to include building relationships with key technical universities with the intent of facilitating campus hiring and further developing the technical skills of ISO-NE's existing population.

New York

Demand — The New York area is a summer-peaking system, and summer peak demands are expected to grow at an average rate of 0.9 %, through 2017. This compares with 1.2 % growth projected in the 2007-2016 assessment conducted by the RAS in 2007. The forecast developed by the NYISO is based on historical weather-normalized loads provided by the transmission-owners of New York State. At peak load levels, a one-degree increase in the cumulative temperature-humidity index (CTHI) above the design value of 84.2 will result in about 610 MW of additional load. (The CTHI is a three-day heat index based on the dry bulb and wet bulb temperatures.)

Energy consumption is forecast to grow at an average annual rate of 1.2 % through 2017. This compares with 1.4 % growth projected in the 2007-2016 assessment conducted by the RAS in 2007. The decrease in demand and energy projections are the result of weaker long term economic growth projections, revisions to historical economic time series, and new planned energy conservation activities of local utilities.

For Load Forecast Uncertainty, the New York ISO develops 90% confidence intervals about its long term energy and demand forecasts. In our Installed Reserve Margin Studies, we determine the load forecast uncertainty at seven separate load levels. The middle load level represents a 50th percentile load forecast and is our base case forecast. The remaining six load levels are distributed at plus and minus 1, plus and minus 2, and plus and minus 3 standard deviations of the mean of the peak-producing weather index.

Resources — New York's Reliability Needs Assessment (RNA) provides a forecast of planned capacity resources over the study period. Table NYBA-1 below shows this projection with the wind and biomass portions of the total in-state capacity resource mix segregated out. The uncertainties for wind and hydro units are broken out, as well. Details of planned additions, re-ratings and retirements can be found in NYISO's 2008 Load and Capacity Data Book[163]

Table NYBA -1

NYBA Planned Resource Capacity Mix
By Year

Fuel Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Coal	3,105	2,803	2,803	2,803	2,803	2,803	2,803	2,803	2,803	2,803
Gas & Oil	14,515	14,746	14,746	14,515	14,515	14,515	14,515	14,515	14,515	14,515
Gas	6,467	6,467	6,467	6,467	6,467	6,467	6,467	6,467	6,467	6,467
Hydro	5,636	5,666	5,704	5,734	5,734	5,734	5,734	5,734	5,734	5,734
Nuclear	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265
Oil	3,325	3,325	3,325	3,325	3,325	3,325	3,325	3,325	3,325	3,325
Biomass	357	364	370	370	370	370	370	370	370	370
Wind	424	443	449	449	449	449	449	449	449	449
w/recent Wind*	707	726	732	732	732	732	732	732	732	732
Total	**39,378**	**39,362**	**39,412**	**39,211**	**39,211**	**39,211**	**39,212**	**39,212**	**39,212**	**39,212**
Certain	38,269	38,237	38,282	38,081	38,081	38,081	38,081	38,081	38,081	38,081
Uncertain	1,108	1,125	1,130	1,130	1,130	1,130	1,131	1,131	1,131	1,131

* Three wind farms totaling an additional 283 MW have recently begun operation.

The New York Independent System Operator (NYISO) applies a 45% derate factor for non-New York Power Authority (NYPA) hydro generation for the expected peak months of July and August. The 45% de-rate factor is applied to the total available non-NYPA hydro generators totaling 1,040 MW. The large NYPA projects (St. Lawrence and Niagara) have specific derate factors based on the probability the unit will be at certain percentages of its rated output.

Wind and ambient readings taken near projected wind sites determine wind unit output over the course of a study year. This method has resulted in average availability rates of 10-11% during summer weekday peak periods (2 pm through 5 pm) with roughly 30% annual capacity factors. With 707 MW of wind generation capacity for this summer, the expected on-peak capacity counted is 71 MW from wind generators.

Two load response programs for the New York Market were introduced in May 2001. The Special Case Resource (SCR) and Emergency Demand Response Program (EDRP) are programs in which Customers are paid to reduce their consumption by either interrupting load or switching to emergency standby generation when requested by the NYISO.

The EDRP program is classified as load relief and the SCR program as capacity resources. These programs currently provide about 300 MW and 1,300 MW of load relief, respectively.

[163] NYISO's 2008 Load and Capacity Data Book can be found at: http://www.nyiso.com/public/services/planning/planning_data_reference_documents.jsp

Purchases and Sales— For 2008, the NYISO projects capacity backed energy net purchases into the New York Balancing Authority area backed by 2,802 MW of generating capacity.

Table NYBA-2 below shows the projection for firm contracts excluding the short term contracts mentioned above.

Table NYBA-2
New York Purchases and Sales

PURCHASE FROM	SOLD TO	MEGAWATTS										
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PEAK - PURCHASES												
ISO-NE	NYISO	380.0	380.0	150.0	150.0	150.0	150.0	100.0	100.0	100.0	100.0	100.0
PJM	NYISO	0.0	0.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0
	TOTALS	**380.0**	**380.0**	**810.0**	**810.0**	**810.0**	**810.0**	**760.0**	**760.0**	**760.0**	**760.0**	**760.0**
PEAK - SALES												
NYISO	ISO-NE	101.1	101.1	732.1	91.1	91.1	91.1	91.1	91.1	91.1	91.1	91.1
NYISO	PJM	73.1	73.1	73.1	73.1	73.1	73.1	73.1	73.1	73.1	73.1	73.1
NYISO	ECAR	129.0	129.0	129.0	129.0	129.0	129.0	129.0	129.0	129.0	129.0	129.0
	TOTALS	**303.2**	**303.2**	**934.2**	**293.2**	**293.2**	**293.2**	**293.2**	**293.2**	**293.2**	**293.2**	**293.2**

Fuel — Traditionally, the New York Area generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While New York is clearly dependent on fossil fuels, the risk of interruption to a single source is mitigated by the large portion (37%) of units that can switch from natural gas to other fuel types such as residual or distillate oil.

The following figure depicts New York's resource capacity mix by fuel type for the year 2008 on an installed capacity basis.

Figure NYBA-1:
2008 NYBA Capacity by Fuel Type

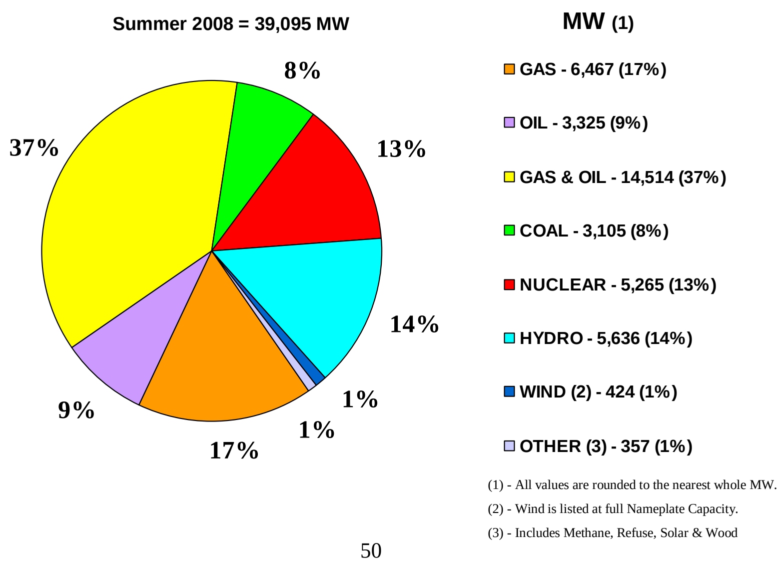


Table NYBA-2 below shows how the Capacity fuel mix changes over the study period.

TABLE[164] NYBA-2

Planned Resource Capacity Mix By Year										
Fuel Type	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Coal	7.9%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%
Gas & Oil	37.1%	37.7%	37.7%	37.3%	37.3%	37.3%	37.3%	37.3%	37.3%	37.3%
Gas	16.5%	16.5%	16.5%	16.6%	16.6%	16.6%	16.6%	16.6%	16.6%	16.6%
Hydro	14.4%	14.5%	14.6%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%
Nuclear	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%
Oil	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%
Biomass	0.9%	0.9%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Wind	1.1%	1.1%	1.1%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%

164 Only proposed resource additions identified in the NYISO Load and Capacity Data book and included in the NYISO Reliability Needs Assessment (RNA), are considered.

The above table shows the projected installed capacity resource mix from 2008 through 2017. For the next ten years, resources fueled by natural gas, hydro, biomass, and wind will meet all of the growth in projected energy consumption.

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 need 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 a 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 & 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 nearly 7,000 MWs greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10%, there is sufficient generation in the low to moderate fuel risk categories to meet the winter electrical peak of 25,500 MW. This would leave a margin of nearly 4,000 MW or 14% of the total capacity characterized by low to moderate fuel risk.

The NYISO continues to work with regulators and other interested parties on a host of environmental initiatives aimed at encouraging the development of new cleaner generation and reducing emissions from existing generation. The four programs with the potential to have the most impact on the power sector are; The New York State Renewable Portfolio Standard (RPS), NOx Emission Reduction of the Ozone Transport Commission, New York State Consent Orders, and the Regional Greenhouse Gas Initiative. A more complete description of these initiatives can be found in the NYISO Power Trends document dated February 2008.[165]

[165] http://www.nyiso.com/public/webdocs/newsroom/press_releases/2008/nyiso_ptrendsfinal08.pdf

The effects of the RPS and Consent orders are captured in the above forecasts for resources in new plants and retirements, respectively. Plans are currently being developed to address compliance in New York for the other two mentioned initiatives.

***Transmission* —**Upgrades in the Rochester vicinity have been completed in preparation of the Russell Station retirement this summer. A capacitor bank is scheduled to be added to the Millwood 345 kV substation by November 2008, for added voltage support in the lower Hudson Valley and Athens Special Protection System (SPS). Also planned for this summer (June or July) is the re-conductor of the Northport – Norwalk Harbor 138 kV cable. The new cable will have three circuits and operate at the same ratings as the current cable.

Additional improvements over the study period are identified on the table appearing on the next page.

Transmission Owner	Terminals		Line Length miles *	Expected Service Date/Yr Prior to	**	Nominal Voltage in kV Operating	Design	# of ckts	Thermal Ratings in Amperes Summer	Winter	Type of Construction & Conductor Size	
Merchant												
East Coast Power, LLC	PSE&G 230 kV	Linden Cogen 345kV		2010		345	345				Variable Frequency Transformer	
Transmission Owner												
Firm Plans												
CHGE	E. Fishkill	E. Fishkill	xfmr #2	2008	S	345/115	345/115	1	440MVA	560MVA	Transformer #2 (Standby)	
CHGE	Hurley Ave	Saugerties	11.11	2011	W	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	E. Fishkill	Wiccopee	3.320	2011	S	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	Saugerties	North Catskill	12.25	2011	W	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	Hurley Ave	North Catskill	23.36	2012	S	115	115	1	1114	1359	1-795 ACSR	OH
CHGE	Pleasant Valley	Knapps Corners	17.7	2017	W	115	115	1	1114	1359	1-795 ACSR	OH
ConEd	Sprain Brook	Sherman Creek	10	2011	S	345	345	1	872	1010	2000 CU	UG
LIPA	Riverhead	Canal	16.4	2011	S	138	138	1	1056	1204	2500 MCM Cu Sol Dielect	UG
LIPA (4)	Pilgrim	Brentwood	4.56	2012	S	138	138	1	2343	2506	1272 SSAC	OH
LIPA (4)	Pilgrim	Brentwood	4.56	2012	S	138	138	2	2343	2506	1272 SSAC	OH
LIPA (4)	Pilgrim	Brentwood	4.18	2012	S	138	138	3	2343	2506	1272 SSAC	OH
LIPA	New Brentwood	Brentwood PS	Phase Shifter	2012	S	138	138	1	-	-	Phase Shifter	-
LIPA	Brentwood PS	Holtsville GT	12.4	2012	S	138	138	1	2343	2506	1272 SSAC	OH
LIPA	Barrett	Bellmore PS	Phase Shifter	2012	S	138	138	1	-	-	Phase Shifter	-
LIPA	Bellmore PS	Bellmore	8.4	2012	S	138	138	1	1150	-	2000 mm2 Cu	UG
LIPA (5)*****	Northport	Narwalk Harbor	11	2014	S	138	138	3	675	675	3/C XLPE Cu 800mm2	UW / UG
NYPA*	Willis 1	Plattsburgh	-33.700	2008/2009	W	230	230	1	426	545	1-795 ACSR	OH
NYPA*	Willis 2	Plattsburgh	-33.700	2008/2009	W	230	230	2	426	545	1-795 ACSR	OH
NYPA****	Willis 1	Patnode	9.100	2008/2009	W	230	230	1	426	545	1-795 ACSR	OH
NYPA****	Patnode	Duley	15.270	2008/2009	W	230	230	1	426	545	1-795 ACSR	OH
NYPA****	Duley	Plattsburgh	9.32	2008/2009	W	230	230	1	426	545	1-795 ACSR	OH
NYPA****	Willis 2	Ryan	6.460	2008/2009	W	230	230	2	426	545	1-795 ACSR	OH
NYPA****	Ryan	Plattsburgh	27.24	2008/2009	W	230	230	2	426	545	1-795 ACSR	OH
NYSEG (7)	Wood Street	Carmel	1.34	2009	S	115	115	1	775	945	477 ACSR	OH
NYSEG (7)	Wood Street	Katonah	11.7	2009	S	115	115	1	775	945	477 ACSR	OH
NYSEG ***	Etna	Lapeer	14.950	2010	W	115	115	1	1410	1725	1277 KCM ACAR	OH
NYSEG	Etna	Lapeer	14.950	2010	W	115	115	1	1410	1725	1277 KCM ACAR	OH
NYSEG	Lapeer	Lapeer	xfrm	2010	W	345/115	345/115	1	200MVA	220MVA	Transformer	
NYSEG	Lapeer	Lapeer	xfrm	2010	W	345/115	345/115	1	200MVA	220MVA	Transformer	
NGRID	Paradise Ln 115 kV	Paradise Ln 115 kV	-	2010	S	-	-	-	-	-	115 kV Switchyard	-
O & R	Ramapo	Sugarloaf	16.000	2009	W	138	138	1	1089	1298	2-1590 ACSR	OH
RGE	Station 135	Station 424	4.98	2009	S	115	115	1	1135	1415	1033 AL	OH
RGE	Station 135	Station 424	4.977	2009/2010	W	115	115	1	1225	1495	1-1033.5 ACSR	OH
Non-Firm Plans												
NGRID	South Saratoga (New Station)	Luther Forest #W (New Station)	2.8	2009	S	115	115	1	TBD	TBD	New 115 kV line (2.8 miles new; 8.9 miles exist)	
NGRID	South Saratoga (New Station)	Luther Forest #X (New Station)	2.8	2009	S	115	115	1	TBD	TBD	New 115 kV line (2.8 miles new; 8.9 miles exist)	
NGRID	North Troy	Luther Forest #Y (New Station)	5.9	2009	S	115	115	1	TBD	TBD	New 115 kV line (5.9 miles new; 30.3 miles exist)	
NGRID	Mohican	Luther Forest #Z (New Station)	5.9	2009	S	115	115	1	TBD	TBD	New 115 kV line (5.9 miles new; 12.1 miles exist)	
NGRID	Rotterdam	South Saratoga #3 (New Station)	11	2009	S	115	345	1	TBD	TBD	New 115 kV line (to be converted to 345kV)	
NGRID	Gardenville	Homer Hill	21	2010	S	115	115	2	TBD	TBD	115 kV line Replacement	-
NGRID	Falconer	Warren	19.4	2011	S	115	115	1	TBD	TBD	115 kV line Replacement	-
NGRID	Mortimer	Golah	9.6	2011	S	115	115	1	TBD	TBD	New 115 kV line	-
NGRID	Spier	South Saratoga #3 (New Station)	21.7	2011	S	115	115	1	TBD	TBD	New 115 kV line	
NGRID	Rotterdam	South Saratoga #4 (New Station)	11	2012	S	115	345	1	TBD	TBD	New 115 kV line (to be converted to 345kV)	
NGRID	Southwest 345 kV	Southwest 115 kV	-	2012	S	-	-	-	-	-	345/115 kV Stepdown	-
NGRID	Packard	Paradise	13.5	2013	S	115	115	1	TBD	TBD	115 kV line Replacement	-
NGRID	Paradise	Gardenville	13.5	2013	S	115	115	1	TBD	TBD	115 kV line Replacement	-
NGRID	Packard	Gardenville	27	2013	S	115	115	1	TBD	TBD	New 115 kV line	-
NGRID	Princetown (New Station)	South Saratoga #3 (New Station)	17	2018	S	345	345	1	TBD	TBD	New 345kV Line reconfig/convert from 115kV above	
NGRID	Princetown (New Station)	South Saratoga #4 (New Station)	17	2018	S	345	345	1	TBD	TBD	New 345kV Line reconfig/convert from 115kV above	
O & R	Lovett	Lovett	xfrm	2013	S	345/138	345/138	1	501 MVA	501 MVA	Transformer	

(7) '115 kv operation as opposed to previous 46 kv operation

(5) Cable replacement; LIPA owns 50% of the NUSCO cable

(4) 138 kv operation as opposed to previous 69 kv operation

***** Partial NUSCO upgrade will be done in 2008 and full NUSCO upgrade is scheduled for 2014 (including Northport-Pilgrim Upgrade)

**** Lines resulting from tapping of Existing Circuit

*** Reconductoring of Existing Line

** S = Summer Peak Period W = Winter Peak Period

* Line Length Miles - negative values indicate removal of Existing Circuit being tapped

Operational Issues — No unusual operational issues have been identified for the period 2008-2017.

Reliability Assessment Analysis — The NYISO conducts an annual Reliability Needs Assessment (RNA)[166] that examines both resource and transmission needs over a ten year period. Resources totaling approximately 455 MW as well as transmission upgrades that are under construction or otherwise have met the screening criteria are included in the base case. The RNA determined that sufficient statewide resources are available to meet NPCC LOLE criteria through the year 2011. For 2012, the RNA indicates that sufficient resources would exist if 500 MW were added to New York City (NYC) or 750 MW were added in the Lower Hudson Valley or if transfer limits into NYC were increased. Beyond 2012, additional resources of approximately 2,750 MW would be needed to meet the criteria through 2017; a majority of those resources would needed to be in the NYC zone to meet the NYC zonal requirements.

Subsequent to the RNA, the NYISO solicits solutions to address the needs identified in the RNA. In response to this solicitation, market based solutions and regulated backstop solutions are proposed. Transmission Owner (TOs) plans subsequent to the RNA initiation are also evaluated by the NYISO and included in the assessment or evaluation of the proposed solutions. These TO plans will satisfy the reliability needs through 2012. Sufficient market based solutions have been proposed to more than meet the needs through 2017. If sufficient market solutions are not proposed or do not proceed, the responsible TOs are obligated, under the NYISO reliability planning process, to proceed with the implementation of the regulatory backstops and/or gap solutions when needed to meet any identified reliability needs.

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. This test would become part of the NYISO's interconnection process. Resources that were 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 is deliverable.

NYISO conducts semi-annual and monthly Installed Capacity (ICAP) auctions. Based on the forecast load for 2008, the ICAP requirement is 38,879 MW based on a 15% Installed Reserve Margin (IRM) requirement. Last year the IRM requirement was 16.5%. On February 29, 2008, the Federal Electric Regulatory Commission issued an order accepting the New York State Reliability Council's filing of a 15% 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 that the amount of generation that is accepted as ICAP in New York will not be sold elsewhere. The external Balancing Authority in which the supplier is located has to agree that the supplier will not be recalled or curtailed to support its own loads; or will treat the supplier using the same pro rata curtailment priority for resources within its Control Area. The energy that has been accepted as ICAP in New York must be demonstrated to be deliverable to

[166] NYISO Report titled "Comprehensive Reliability Planning Process (CRPP) – 2008 Reliability Needs Assessment", December 12, 2007

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.

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 NYISO conducts the Locational Capacity Requirements study which 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% of the New York City peak load be secured from within its zone and capacity totaling 94 % of Long Island peak load be secured within that zone, for the 2008-2009 capability years. The NYISO also performs an LOLE analysis that determines the maximum amount of ICAP contracts that can originate from Balancing Authorities external to the New York Balancing Authority area.

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

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

The Beck-Packard BP76 230kV line is out of service for this summer, currently scheduled to return to service by late in the summer of 2010.

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

The NYISO performs seasonal operating planning studies to calculated and analyze system limits and conditions for the upcoming operating period. The operating studies include calculations of thermal transfer limits of the internal and external interfaces of the New York Balancing 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.

Other Reliability Assessment Information — A number of issues that were indicated in the LTRA instructions have been addressed in the NERC Resource Issues Subcommittee Resource Adequacy Survey that was supplied by the NYISO to NERC on May 30, 2008.

Ontario

Demand - Ontario's forecast of demand is based on Monthly Normal weather. The economic forecast is based on the most recent information and predicts a fairly neutral growth for Ontario in 2008 and 2009, followed by modest economic growth. The impacts of the high Canadian dollar, the current economic climate and particularly the considerable impacts from planned conservation and growing load-displacing generation is stabilizing Ontario's load growth and moving it in the direction of gradual, intentional decline.

Due to the economic, conservation and load-displacing generation impacts, demand is expected to shrink over the course of the forecast. Peak demand is expected to average declines of 0.5% per year and annual energy demand is expected to average declines of 0.9% per annum. This is in contrast to last year's forecast where peak demand had average annual decreases of 0.2% and energy demand was expected to grow by 0.4%.

Ontario has a number of demand response programs that can reduce demand. A number of consumers within the province bid their load into the market and are responsive to price through IESO to dispatch instructions. Other consumers have been contracted by the Ontario Power Authority (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 more than 800 MW in total, of which two thirds 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 to more than 500 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 studies the reliability of the system prior to the impact of planned conservation savings. The IESO did not look at alternate economic scenarios.

Generation - The total capacity of existing installed resources connected to the IESO controlled grid is 31,297 MW, of which the amount of 'certain' capacity is 28,194 MW for summer 2008. The remainder, 3,103 MW, is 'uncertain' capacity for 2008 which includes on-peak resource deratings, planned outages and transmission-limited resources.

About 300 MW of dependable new supply (394 MW installed) is scheduled to come into service before the 2008 summer peak period. All of this new supply, with one exception, is gas-fired generation, including 340 MW of generation (250 MW under contract and considered dependable) in downtown Toronto from the first, simple cycle phase of a 550 MW combined cycle energy centre to be completed by summer 2009 and 31 MW of Combined Heat and Power projects in several locations around the province. A hydroelectric project with an installed capacity of 23 MW will, also, come into service before summer 2008. Eighty percent of this new installed hydroelectric capacity is assumed to be available at the time of weekly peak.

The existing installed capacity of wind generation connected to the IESO controlled grid is 471 MW. Ten percent of the installed wind capacity is assumed to be available at the time of weekday peak, thus, 47 MW of wind is considered certain for capacity planning purposes. Of the 75 MW of installed biomass generation in the province, 45 MW is assumed certain. The generation output of some biomass units has been reduced as a consequence of reductions in steam demand primarily from pulp and paper operations.

The table below lists the certain and uncertain capacities for Existing, Planned and Proposed resources for summer 2008 to 2017.

	Projected									
DESCRIPTION	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Existing Total Certain Capacity	28194	28123	26041	25072	24504	24593	24593	20230	18759	18553
Wind Expected On-Peak	47	47	94	94	94	94	94	94	94	94
Hydro Expected On-Peak	5869	5869	5869	5869	5869	5869	5869	5869	5869	5869
Biomass Expected On-Peak	45	45	45	45	45	45	45	45	45	45
Existing Total Installed Capacity	31297	31297	31297	29832	28156	27991	27991	24394	24287	24081
Existing Installed Wind Capacity	471	424	377	377	377	377	377	377	377	377
Existing Installed Hydro Capacity	7788	7788	7788	7788	7788	7788	7788	7788	7788	7788
Existing Installed Biomass Capacity	75	75	75	75	75	75	75	75	75	75
Planned Total Certain Capacity	299	4013	5954	5969	5969	5969	5969	5969	5969	5969
Wind Expected On-Peak	0	63	158	173	173	173	173	173	173	173
Hydro Expected On-Peak	18	22	29	29	29	29	29	29	29	29
Biomass Expected On-Peak	0	0	0	0	0	0	0	0	0	0
Planned Total Maximum Capacity	304	4595	6599	6675	6675	6675	6675	6675	6675	6675
Planned Maximum Wind Capacity	0	631	789	865	865	865	865	865	865	865
Planned Maximum Hydro Capacity	23	36	43	43	43	43	43	43	43	43
Planned Maximum Biomass Capacity	0	0	0	0	0	0	0	0	0	0
Proposed Total Certain Capacity	0	0	58	650	1380	3137	3925	4388	4735	4773
Wind Expected On-Peak	0	0	0	115	115	190	272	317	364	379
Hydro Expected On-Peak	0	0	58	185	404	446	558	604	743	753
Biomass Expected On-Peak	0	0	0	0	61	101	144	212	373	386
Proposed Total Maximum Capacity	0	0	81	1205	2060	4130	5286	5947	6533	6635
Proposed Maximum Wind Capacity	0	0	0	575	575	948	1359	1585	1820	1895
Proposed Maximum Hydro Capacity	0	0	81	280	624	680	832	895	1085	1099
Proposed Maximum Biomass Capacity	0	0	0	0	61	101	144	212	373	386

The process used to select Planned and Proposed capacity resources is the Ontario Power Authority's Integrated Power System Plan. Established in 2005, the Ontario Power Authority (OPA) is the electricity system planner for the province of Ontario.

The OPA's statutory objects require it to, among other things; 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 relating to the government's electricity goals. In addition, the IPSP must develop appropriate procurement processes for managing electricity supply, capacity and demand in accordance with the IPSP and 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, and is currently under regulatory review. The IPSP covers a period of twenty years, complies with the goals and requirements set out by the government of Ontario and proposes a procurement process for managing electricity supply, capacity and demand in accordance with the IPSP.

Purchases and Sales - At present, there is no Firm, Non-Firm or Expected purchases from other regions. Transactions under study (i.e. provisional) are imports from Labrador and Manitoba.

The IESO has agreements in place with neighbouring jurisdictions in NPCC, RFC and MRO for emergency imports and reserve sharing, should they be required in day to day operations.

Fuel - The Ontario fuel supply infrastructure is judged to be adequate, and there are no fuel delivery problems anticipated. Nine per cent of the existing generation capacity in Ontario is gas-fired. The percentage of gas generation will increase to 26% by 2017 as coal generation is retired. Gas pipeline capacity, historically, has not limited the summer energy or capacity capability of Ontario generation fuelled solely by natural gas and is not expected to be a problem for future summers. Similarly, no fuel delivery concerns have been identified for coal-fired generating stations. In its market manuals, the IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel-supply limitations are anticipated. No limitations have been reported for the summer months.

The province is not experiencing a drought at present. Hydroelectric outputs are based on the median historical values of hydroelectric production and contribution to operating reserve during the weekday peak hours. The median hydroelectric value assumed available for annual peak is about 75% of the total installed capacity.

Transmission - Hydro One and TransÉnergie are building a 1,250 MW interconnection between Hawthorne TS in Ontario and Outaouais station in Quebec consisting of a double circuit 230 kV line and back-to-back high-voltage direct-current (HVdc) converters at Outaouais. Work to accommodate the tie, scheduled to be in service before summer 2009, will also include improvements to load serving capabilities in the Ottawa area.

The existing special protection system (SPS) at St. Lawrence was modified, allowing increased westward transfers. This SPS, which rejects generation at Saunders GS for circuit contingencies between eastern Ontario and the Toronto area, is planned to be enhanced further, to increase its functionality and reliability under peak load conditions, and to maximize simultaneous import capability from Hydro Québec and New York. These future enhancements will be required in 2009 upon completion of the new 1,250 MW Ontario-Québec interconnection.

Over the next decade, the need for transmission enhancements is particularly evident in three areas of the Ontario:

- In south-western Ontario to deliver additional nuclear and wind supply from the Bruce area,
- In northern Ontario to enable the planned expansion of hydroelectric and wind capability and to reinforce the connection of these areas to the load centre in southern Ontario
- In the Toronto region in order to meet capacity needs of fast growing areas in the Greater Toronto Area and to improve reliability to Canada's largest city.

The southwestern Ontario transmission system needs to be enhanced to deliver the planned and future increases in generating capability in and around the Bruce peninsula. Currently, there is inadequate transmission out of the Bruce area to accommodate both the expected wind developments in that area and the expanded capacity of the Bruce nuclear station resulting from planned refurbishments. Some near-term reinforcements include the up-rating of the Hanover to Orangeville 230 kV circuits, and the installation of additional voltage support facilities at various transmission stations in southwestern Ontario. These will increase the transfer capability out of Bruce in the short-term. The proposed 500 kV double circuit line from Bruce to Milton received the OEB approval for leave to construct on September 15, 2008. This represents a significant milestone in the approval process and the line is planned to go into service in December 2011. The line will provide the required transmission capability over the long-term to deliver the full capability of the Bruce refurbishment and both planned and potential new renewable resources in the Bruce area. The new 500 kV line out of the Bruce area is required to accommodate the additional generation from both new wind projects and refurbished Bruce nuclear units.

As the Nanticoke coal-fired station is phased out by 2014, additional voltage support in southwestern Ontario will be required. Both static and dynamic reactive power solutions are being considered, ranging from shunt capacitors to possible replacement generation.

Over the next few years, over 1,600 MW of contracted gas-fired generation will be coming in-service in the Sarnia area. This will significantly increase the amount of power flowing between the Sarnia area and the London area and stress the existing transmission system west of London. The planned retirement of the Lambton coal-fired generating plant (2,000 MW) early next decade, however, will reduce this transmission concern. Thus, there is currently no plan to reinforce the transmission west of London. This need will be monitored into the future as new generating resources such as renewables and combined heat and power projects are proposed in the Sarnia and Windsor-Essex areas.

Transmission enhancements in the northeastern part of the Ontario grid are required to allow the delivery of planned generation from that area to southern Ontario. The proposed enhancements, including series capacitors at Nobel TS, and a static var compensator (SVC) in northeastern Ontario, are expected to relieve existing congestion and accommodate the additional output from the proposed expansion of the four existing hydroelectric stations on the Lower Mattagami River and other committed renewable energy developments in northeastern Ontario.

The development of enabling transmission reinforcements is planned to integrate additional renewable resources procured in the northern parts of Ontario and to connect these areas to the load centre in southern Ontario.

The continuous economic growth experienced in parts of Ontario in the last decade has resulted in the loads in a number of areas reaching or exceeding the capability of the existing transformer stations and/or their supply lines. Some large load centers also have concerns with supply security. To address these needs and provide additional local area supply capacity for future load growth, work has commenced on a number of area supply projects.

Phase angle regulators (PARs) are installed on the Ontario-Michigan interconnection at Lambton TS, representing two of the four interconnections with Michigan, but are not currently available to regulate flows on the interconnection except in emergencies. These PARs are expected to become operational by the end of 2008. The operation of the these PARs along with the PAR on the Ontario-Michigan interconnection near Windsor will control flows to a limited extent, and assist in the management of system congestion.

The capability to control flows on the Ontario-Michigan interconnection between Scott TS and Bunce Creek is unavailable. The PAR installed at Bunce Creek in Michigan has failed and is scheduled for replacement in 2010.

The table below lists the transmission projects that are planned for completion within the next ten years. They are considered to provide significant improvement to system reliability.

Transmission Project Name			Voltage (kV)	Length (Miles)	In-service Date(s)	Description/Status
Cardiff TS	to	Hurontario SS	230	3	05-2010	Under Construction
Hurontario TS	to	Jim Yarrow TS	230	3	05-2011	Under Construction
Hurontario SS					05-2010	Under Construction
Ingersoll Jct.	to	Woodstock-Karn TS	230	7	04-2011	Construction Imminent
Essa TS	to	Stayner TS	230	17	04-2009	Under Construction
Nobel SS Series Compensation			500		12-2010	Construction Imminent
Porcupine TS SVC			230		11-2010	Construction Imminent
Bruce GS	to	Milton TS	500	115	12-2011	EA Approval Phase
Allanburg TS	to	Middleport TS	230	50	To be determined	On-hold
Outaouais SS	to	Hawthorne TS	230	14	06-2009	Under Construction
Nanticoke TS SVC			500		2011	Planning Phase
Detweiler TS SVC			230		2011	Planning Phase
Lakehead	to	Birch	230	13	2013	Planning Phase
Sudbury	to	Greater Toronto Area	500	180-250	2017	Planning Phase
Mississagi TS to Hanmer TS			500	130	2017	Planning Phase
Pinard TS to Hanmer TS			500	230	2017	Planning Phase
Mackay TS to Third Line TS			230	60	2017	Planning Phase
Nipigon TS to Little Jackfish			230 or 115	120	2014	Planning Phase
Seaforth TS	to	Goderich TS	230	25	2015	Planning Phase
Owen Sound	to	Bruce Peninsula	230 or 115	30-50	2015	Planning Phase
Manitowadge	to	Espanola TS	230 or 115	50	2015	Planning Phase

Alternatives for some other are supply projects are being assessed. These include Supply to Essex County and Guelph Area Transmission Reinforcement. Since the terminal points for these have not yet been identified, they are not included in the table above.

There are no major transformer additions planned for in service in the next ten years.

Operational Issues - One of the most important developments in the Ontario system is the planned retirement of all coal fired generation by 2014, an initiative taken in response to a directive issued by the Ontario government. The Integrated Power System Plan developed by the OPA provides a plan to address this resource gap with generation from a number of committed and planned resources. Although this presents a major change in the Ontario system, with careful planning it is anticipated that all operational challenges can be addressed.

At this time, there are no unusual operating condition, environmental, or regulatory restrictions that are expected to affect capacity availability for the next ten years, beyond those identified in the OPA's IPSP.

Reliability Assessment Analysis - The IESO reliability assessments include multi-area resource adequacy assessments as well as transmission adequacy assessments, to determine the deliverability of resources to load. Two major assessments are performed periodically by the IESO.

Every quarter, the IESO prepares an18-Month Outlook which advises market participants of the resource and transmission reliability of the Ontario electricity system, assesses potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment, and reports on initiatives that are being put in place to improve reliability within the 18-month timeframe.

At least once a year, the IESO investigates the adequacy of the Ontario system for the next five years and the key messages are published in the Ontario Reliability Outlook. The assessment processes and the criteria which are followed are described in the documents, "Method to Perform Long-Term Assessments",[167] and "Ontario Resource and Transmission Assessment Criteria."[168]

The IESO determines required reserve levels based on probabilistic methods deemed by NPCC to be acceptable for meeting regional LOLE criteria. In considering what resources contribute to adequacy the IESO assumes that the planned and proposed resource additions can meet their stated in service dates and the forecast amount of conservation can be achieved. At this time, the reserve requirements are met solely with the planned and proposed resources that are internal to Ontario. Should capacity commitments be contracted in future from external entities, these will be included to the extent they are not considered to be capacity in the balancing area from which they may be supplied.

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

Projected capacity reserve requirements, determined on the basis of the IESO's requirements for Ontario self-sufficiency, are.14.5% until 2014 and 15.3% thereafter. IESO routinely assesses resource requirements for the first five years of the ten-year period. In association with the OPA, the periods beyond five years are assessed and resource plans developed as part of the IPSP process. Transmission assessments are conducted, as needed, as far into the future as necessary recognizing the long lead time for significant transmission facility development.

IESO considered only the committed and contracted resources in the 2007 assessment. Projects that are in the planning stage from the IPSP are included in this year's assessment. These projects amount to about 6,600 MW in the next ten years.

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. 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 development of a diverse resource mix, the potential consequence of these events is reduced.

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[167] http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp
[168] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

Although energy supplies available within Ontario are expected to be adequate overall, energy deficiencies could arise as a result of higher than forecast forced outage situations, prolonged extreme weather conditions and other influencing factors. Interconnection capability and available market and operational measures have been evaluated as sufficient 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.

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.

A number of major unit refurbishment or retirement decisions are expected to occur in Ontario by the year 2017. 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). 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, renewable and conservation resources 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. Additional 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 natural gas. Mitigation of reliability concerns is to be supported through ongoing monitoring, assessment, measurement and 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" document. In our 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.

The IESO reviews its system operating limits on an ongoing basis, as warranted by system configuration changes on the grid. In advance of each summer peak season, the IESO analyzes the forecast demand for Ontario, and forecast transmission and generation availability, and assesses the ability of the planned generation to supply the forecast load (in essence its deliverability). Where transfer limits are expected to restrict available generation, these restrictions, in addition to zone-to-zone system operating limits, are factored into the reliability analysis for the season, to determine IESO's resource adequacy. IESO, as the Reliability Coordinator, and via its authority to direct the operation of the IESO-administered market and the IESO-controlled grid, can ensure that generation dispatch does not violate system operating limits. Where resources are expected to be insufficient to satisfy established criteria[169], the IESO can deny final approval for planned outages, and can rely on emergency procedures in the operational time frame to address shortfall conditions.

The IESO regularly conducts transmission studies that include results of stability, voltage, thermal and short-circuit analyses in conformance with NPCC criteria. Since the implementation of the NERC TPL standards in June 2007, the IESO's comprehensive 2007 transmission studies have been conducted to comply with these standards, in addition to NPCC criteria.

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

There are currently no Under-Voltage Load Shedding systems installed in Ontario for the purpose of controlling the voltage on the bulk power system portion of the IESO-controlled grid in response to bulk power system events. 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 the crisis 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 thirty one 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.

[169] NPCC Criteria A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems" and IMO_REQ_0041, "Ontario Resource and Transmission Assessment Criteria"

The province is not experiencing a drought at present. Hydroelectric outputs are based on the median historical values of hydroelectric production and contribution to operating reserve during the weekday peak hours. The median hydroelectric value assumed available for annual peak is about 75% of the total installed capacity.

In 2007, the IESO conducted a Comprehensive 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 and NERC documents, 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 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. It is hoped that this forum will build on the provincial Smart Metering Initiative to install smart meters by 2010 and complements the renewal taking place in Ontario's transmission and generation sectors.

The IESO is developing an on-line limit derivation tool to maximize transmission capability in the operating time frame. This tool is planned to be implemented over the next one to four years.

The Ontario Market Rules obligate anyone planning to connect or modify a connection to the IESO-controlled grid to apply to the IESO for a connection assessment. All connection assessment studies performed by the IESO for connection of new or modified generation and transmission facilities include a short circuit study which identifies the effect of the new facility on the system short circuit levels. In addition, Hydro One periodically performs a short circuit level survey and makes the results available to the IESO. Where short circuit levels are envisaged to exceed the capability of the existing equipment, new equipment with higher ratings is required to be installed if available, or short circuit levels are limited to safe levels by operating the system split during the critical periods.

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.

Other Region-Specific Issues that were not mentioned above -There are no other issues to report.

Québec

Demand[170]

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 plus and minus 3 days to gain information on conditions that occurred during a weekend

[170] http://www.regie-energie.qc.ca/audiences/3648-07/Requete3648/B-1-HQD-01-01_3648_01nov07.pdf

for example. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetic average of those 252 scenarios. The Québec Area produces a high case demand scenario. Economic parameters are set higher and the same method as 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. In modeling, the uncertainty is represented through load multipliers covering errors of two standard deviations. Each load multiplier has a probability of occurrence. Given the global uncertainty, the probability that the actual peak for winter 2007/2008 was in the range of plus and minus 1,700 MW around the forecast peak was 68 % (assuming a normal distribution).

The 2007-2016 average annual growth rate was 0.66 % and the forecast average annual growth rate for 2008-2017 is 0.8 %.

In Québec, there is only one distributor, and accordingly there is no need to aggregate the load forecast. The load forecast incorporates all of Hydro-Québec programs designed to reduce the peak demand. For the 2007-2008 winter period, that reduction represents 890 MW; 2,990 MW is reduced in the winter period 2016-2017.

Generation

Québec has more than 40,000 MW of existing certain capacity. There are more than 2,000 MW of planned and proposed capacity. In summer 2008, there are 420 MW of installed wind capacity and a total of more than 3,000 MW of wind capacity developed by the winter 2013/2014. For biomass, there is 44 MW of installed capacity.

For reliability assessment, Québec considers the installed and planned future capacity (construction has started, or regulatory permits approved or approved by corporate management). The “La Romaine” project (882 MW) is the only future project included in our long term analysis. The in-service date is expected to be late 2014 for the first phase of the project.

Purchases and Sales on Peak

Québec has a 200 MW firm purchase contract with New Brunswick until October 2011. New Brunswick uses the Millbank unit to deliver this contract. Québec has two firm contracts, one with Ontario (145 MW until the end of horizon of this study. The other contract is with New England (310 MW until the end of 2011.

Hydro-Québec Distribution includes, when planning its resources, a potential of 500 MW for interconnection assistance for the winter months. When needed, short term calls for tenders are launched and transmission capacity is reserved for those purchases. Hydro-Québec Production can participate in these calls for tenders.

Fuel

Non-hydraulic resources account only for a small portion of total resources. Plants using oil or jet fuel are refuelled by boat or by truck, and generally not during the winter season. Natural gas is used at a single cogeneration plant, and it is delivered under a firm natural gas purchase contract.

Transmission

Transmission Project Name From / To	Voltage (KV)	Length (Miles)	In-service Dates (In French)
Rimouski / Les Boules	230	34,4	08-déc
Les Boules / Matane	230	58,1	08-déc
Rimouski / Matane	230	5,1	08-déc
Matane Goemon	230	43,8	08-déc
Carleton / Line 2398	230	7,5	08-déc
Les Mechins / Line 23 YY	230	6,3	09-déc
Chenier / Outaouais	315	70,6	10-mai
Eastmain-1A / Eastmain-1	315	1,2	10-juil
Sarcelle / Eastmain-1	315	68,8	10-juil
Goemon / Mont-Louis	315	46,3	10-déc
Goemon / Gros Morne	315	55,6	11-déc
Romaine-2 / Arnaud	315	162,9	14-déc
Romaine-1 / Romaine-2	315	19,1	16-déc

Operational issues

a) There is one anticipated unit outage (Gentilly-2 nuclear unit of 675 MW, from late 2010 to mid-2012) but this outage will not impact reliability. Variable resources, transmission additions and temporary operating measures will not impact reliability in a negative manner during the next ten years.
b) No restriction for the Québec Area.

Reliability Assessment Analysis

To determine whether existing and planned resources provide an adequate level of reliability, the Québec Area uses the NPCC resource adequacy criterion, an LOLE of 0.1 day per year, which gives a required reserve of about 11 % of the peak load for the year of analysis. This percentage can vary if the future resources have different characteristics and/or the load uncertainty varies.

i) An LOLE of 0.1 day/year which gives a required reserve of about 11 % of the peak load for the current year of analysis.
ii) Not counting the import of 200 MW from New-Brunswick, the internal resources are sufficient to meet the resource adequacy criterion.
iii) Each year Québec has to produce resource adequacy assessments for the NPCC and the Québec Energy Board. These assessments are done during the fall for the next winter peak period and the following years. Please refer to the following web sites: http://www.npcc.org/adequacy.cfm and for the last assessment to the Québec Energy Board (November 2007): http://www.regie-energie.qc.ca/audiences/Suivi.html .
iv) There is no significant change from last year's assessment.
v) In Québec, large multi-year water reservoirs allow hydro generation to be available on peak. For all generation, we use the Dependable Maximum Net Capability by month taking account the water head. The capacity should be able to withstand a minimum two

hours per day run. The run of the river hydro units are derated according to specific constraints. Non-hydraulic resources account only for a small portion of total resources. Plants using heating oil or jet fuel are refuelled by boat or by truck and generally not during the winter season. Natural gas is used at a single cogeneration plant and is delivered under a firm purchase contract.

vi) In this reliability assessment, Québec Area includes a high load forecast scenario. All the economic, demographic and energy parameters are upgraded compared to the base case scenario. The load uncertainty is then reduced to just weather considerations. If the criterion (0.1 day/year of LOLE) isn't met, Québec identifies the different ways to restore reliability.

vii) Hydro-electric capacities monthly withstand at minimum 2 hours per day. Intermittent resources are derated according to constraints. Wind resources are not included.

During the assessment period, the Gentilly-2 nuclear station will be out for major repair, but this refurbishment will not impact reliability.

Québec system operator, TransÉnergie, designs and operates the transmission system within all the standards of the electric industry. There are no long term internal transfer limits that impact reliability on the Québec system. Projected transmission margin for the peak period are adequate to carry the net internal demand plus the firm capacity sales. Moreover, enough transmission capability remains on the system to carry additional resources that would be called upon if load is greater then forecast. Generation plants do not share common infrastructures other than the transmission grid. Therefore, no extreme contingencies are foreseeable other than a loss of transmission capacity. During the winter operating period, the day-ahead capacity margin requirement is twice the operational reserve to account for uncertainties on load forecast and on the availability of generating units. Québec is 95 % hydro generation. Energy (water) availability is more a concern then capacity availability. To assess its energy reliability Québec has developed an energy criterion that states that sufficient resources should be available to go through sequences of two or four years of low water inflows having a two percent probability of occurrence. Such assessment is presented three times a year to the Québec Energy Board. For reliability assessment, we considered the installed capacity and planned future capacity (Construction has started, or regulatory permits approved or approved by corporate management).

Region Description

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

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

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

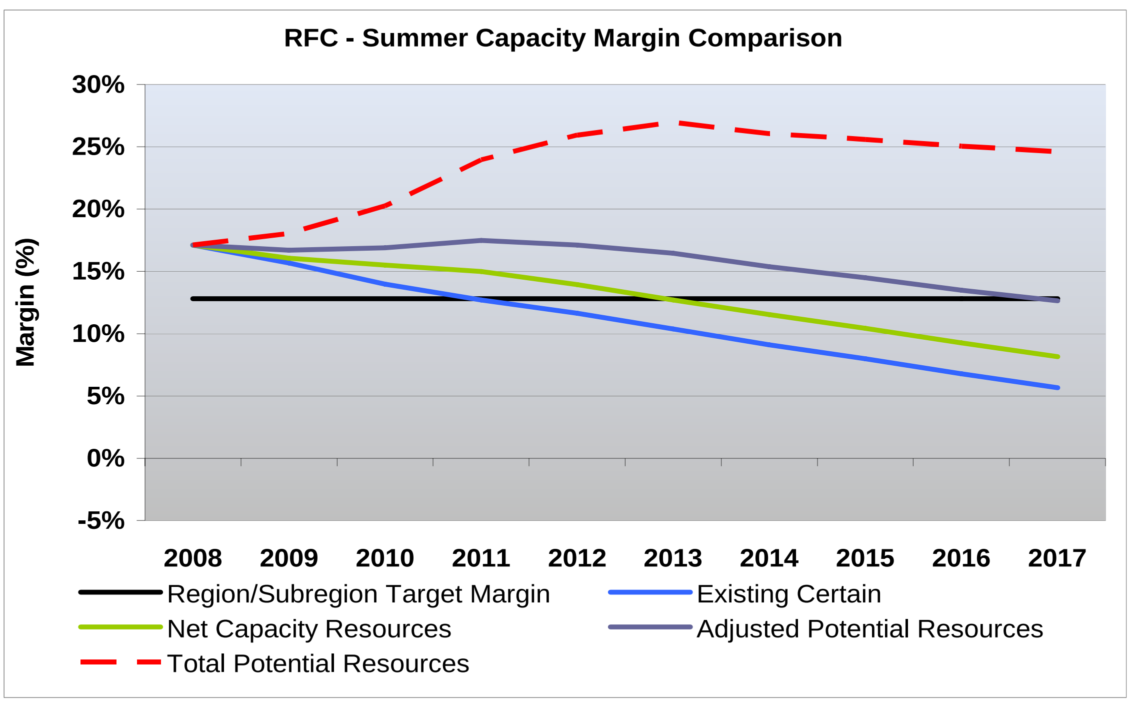
General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of NERC, that has an interest in the reliable operation of the Northeastern North American bulk power system. Full Membership shall be available to entities which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

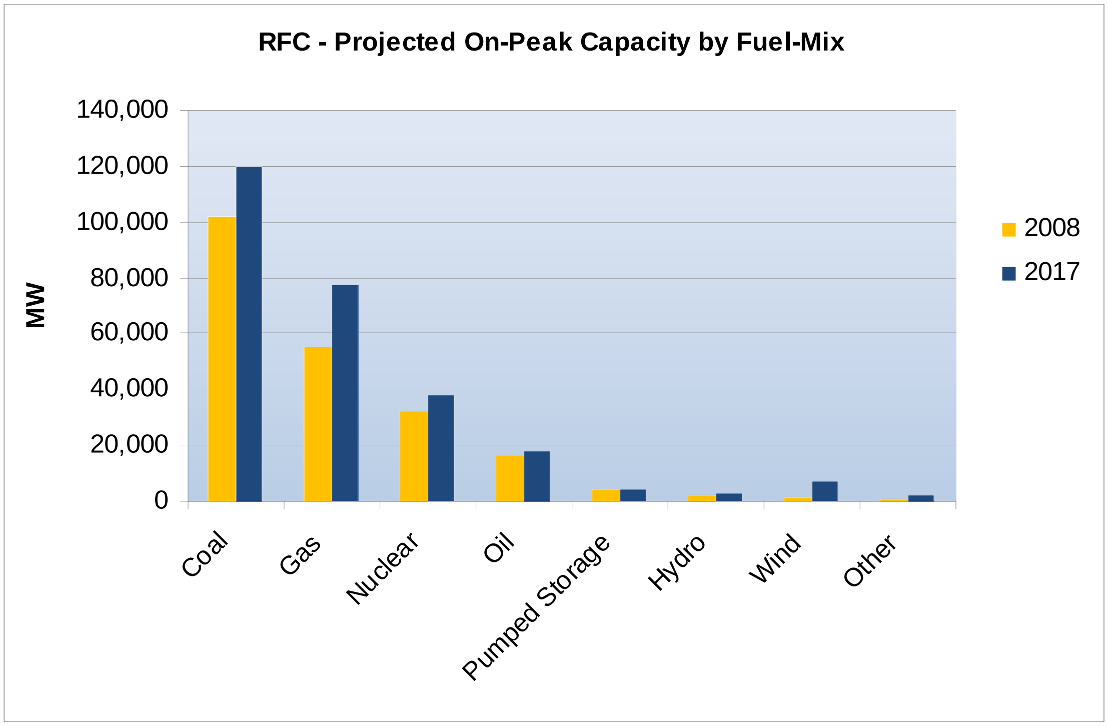
Among the Areas (subregions) of NPCC, Québec and the Maritimes are predominately winter peaking Areas; Ontario, New York and New England are summer peaking systems.

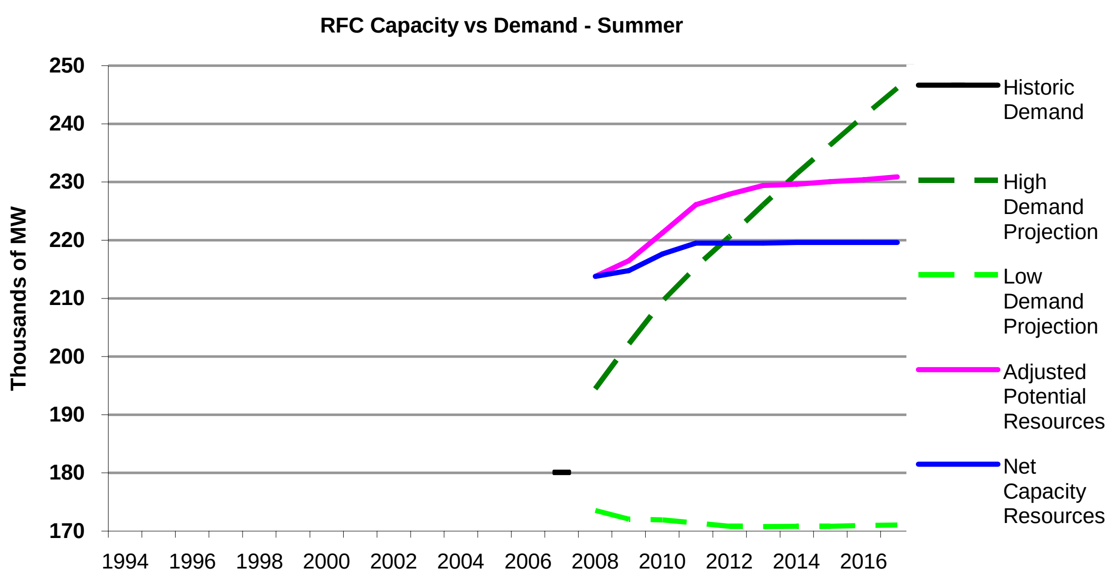
RFC Highlights

The bulk power systems in the Reliability*First* (RFC) region are expected to perform well in meeting the forecast demand obligations over a wide range of anticipated system conditions, as long as operating limits are respected, established procedures are followed and proposed projects are completed in a timely manner. Several major transmission line projects have been announced that are expected to enhance reliability of the transmission network in the eastern areas of RFC. These projects include the Trans-Allegheny Interstate Line (TrAIL), which is in the certification process; the Potomac-Appalachian Transmission Highline (PATH); the 500 kV circuit from Susquehanna to Lackawanna to Roseland; the Mid-Atlantic Power Pathway (MAPP); and a new 345 kV circuit in southern Indiana. Also, the four Phase Angle Regulators (PARs) on the Michigan-Ontario interface are expected to be in-service and regulating by the summer of 2009.

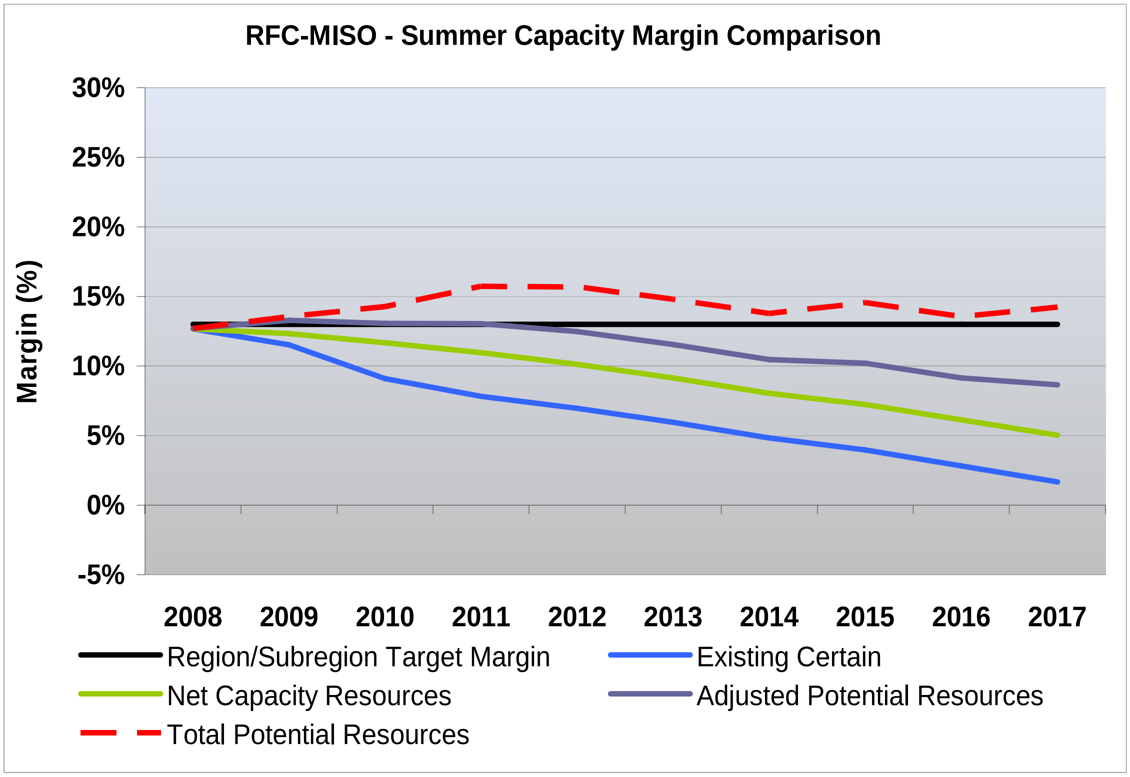
To assess the resource adequacy of the regional area, RFC evaluates the adequacy of the capacity in each RTO to supply the demand in each RTO. The reserve margin targets of each RTO are weight-averaged together to develop a reserve margin target for use in gauging the general adequacy for the RFC region. The amount of proposed resources needed through 2017, in addition to the planned resources, represents only 25.0% of the currently proposed projects in the PJM and MISO generator queues for the Reliability*First* regional area. The expectation is for adequate reserves for PJM, MISO and Reliability*First* throughout the ten year period of this Long Term Resource Assessment.

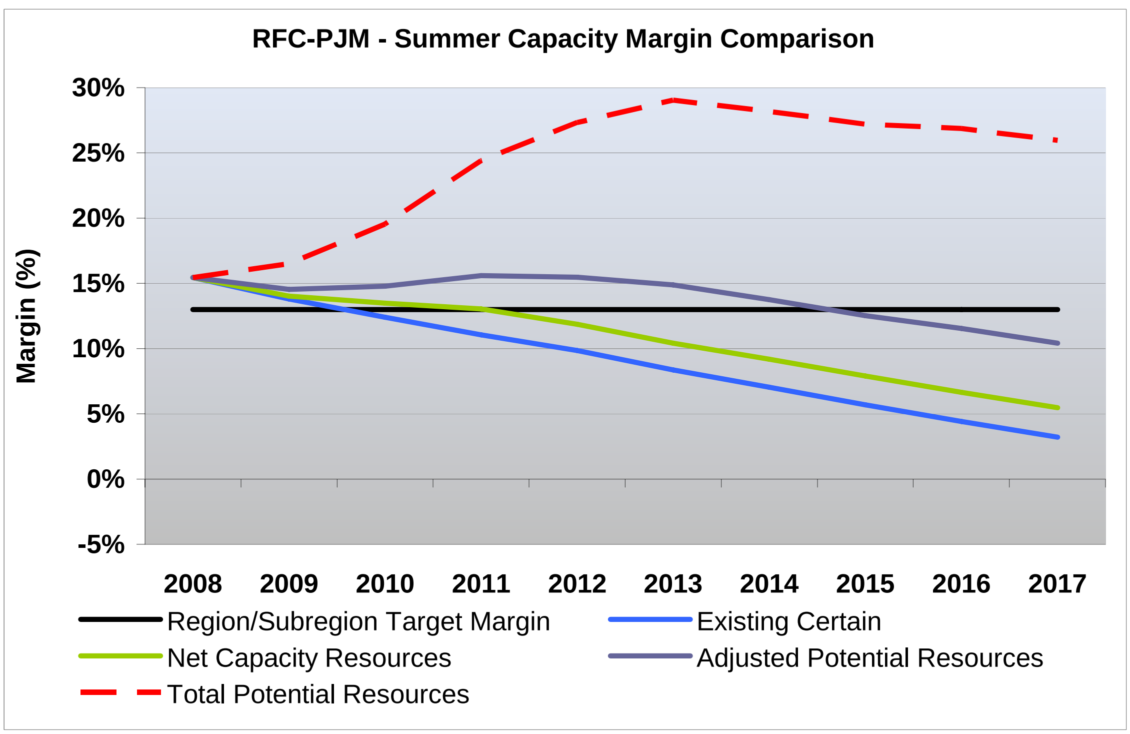






Note that demand data representing RFC's predecessors (portions of the MAIN, ECAR, and MAAC regions) was not considered as part of the analysis performed to obtain the load forecast bandwidths above.


RFC-MISO - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources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Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

RFC Self-Assessment

Introduction

Almost all Reliability*First* Corporation (RFC) members are affiliated with either the Midwest ISO (MISO) or PJM RTO (PJM) for operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission cooperative located in Indiana, Kentucky and Ohio is not affiliated with either RTO market; however OVEC's Reliability Coordinator services are performed by PJM. Duquesne Light Co. has recently announced its intention to withdraw from PJM and join MISO in the third quarter of 2008. For this assessment, Duquesne Light continues to be included within the PJM RTO.

Reliability*First* does not have officially-designated subregions; however, 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 perspective of the RTOs, approximately 60% of the MISO load and 85% of the PJM load is within RFC. The PJM RTO spans into the SERC region, and the MISO RTO also spans into the MRO and SERC regions. The PJM RTO operates in total as one Balancing Authority area. MISO has recently received approval to begin operation as a single Balancing Authority area; however operation as a BA is not expected to occur until the fall of 2008.

This assessment provides information on projected resource adequacy across the Reliability*First* region. The RFC Resource Adequacy Standard BAL-502-RFC-01 requires Planned Reserve Sharing Groups (PRSGs) to identify the minimum acceptable reserves to maintain resource adequacy for their respective areas of RFC. PJM operates as the PRSG for its members. The Midwest PRSG consists of a consortium of MISO members that includes about 95% of the MISO load in the RFC regional area. Since nearly all Reliability*First* area demand is in either Midwest ISO or PJM, the reliability of these two RTOs will determine the reliability of the RFC region. This report assesses the resource adequacy of each RTO based on the reserve margin requirements applicable to each RTO. PJM determines the reserve margin requirement for all demand within PJM. The Midwest PRSG and Mid-Continent Area Power Pool (MAPP) determine reserve requirements for most of the demand in MISO. MISO uses a 12% default reserve requirement for demand not included in the Midwest PRSG and MAPP. The combination of reserves from the Midwest PRSG, MAPP and the default reserve calculation was used by RFC as the MISO reserve margin target for assessing resource adequacy.

Demand

The analysis of the demand data for the long term assessment focuses on three factors, Total Internal Demand (TID), Net Internal Demand (NID) and Demand-Side Management (DSM). This analysis reviews the demand of the entire PJM RTO, Midwest ISO (MISO), as well as the ReliabilityFirst regional area.

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). The PJM RTO prepares the demand forecast for the Load Serving Entities (LSEs) in its operational area. The Midwest ISO aggregates the reported demand forecasts from its Network Customers. The Reliability*First* demand forecast is aggregated from the OVEC demand forecast and the market demand forecast in the Reliability*First* area of PJM and MISO. This is the Total Internal Demand (TID) forecast of the Reliability*First* region. This demand does not include any demand supplied "behind the meter" from customer generation or co-generation. Demand diversity is used to develop coincident demand forecasts for the respective PJM RTO, Midwest ISO and Reliability*First* areas. PJM, MISO and RFC have each developed the diversity factor (2%) for their respective areas.

The Reliability*First* RTOs identify the various programs designed to reduce system demand during the peak periods as DSM. Individual companies may implement DSM through a demand response program, a direct-controlled load program, an interruptible load contract or other contractual load reduction arrangement. Since DSM is a contractual management of system demand, the reserve margin requirement for the RTO includes the effects of DSM. NID is total internal demand (TID) less DSM. Reserve margin requirements are based on NID.

Demand-Side Management can be addressed in different ways, reflective of its operational impact on peak demand and reserve margins. DSM offers the companies that have these programs a way to mitigate adverse conditions that the individual companies may experience during periods of high demand. The total demand reduction of each RTO is the maximum controlled demand mitigation that is expected to be available at the time of the peak system demand.

For this long term assessment, the Reliability*First* RTOs have identified the following types of DSM programs:

> DIRECT-CONTROLLED LOAD MANAGEMENT
> There are a number of load management programs under the direct control of the system operators that allow interruption of demand (typically residential) by controlling specific appliances or equipment at the time of the system peak. Radio controlled 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.
> The projected effects of existing and proposed new non-controlled Demand-Side Management (DSM) programs (such as conservation and energy efficiency incentives) are factored into the TID forecasts provided to Reliability*First*.

PJM RTO DEMAND DATA
The estimated Net Internal Demand (NID) peak of the entire PJM RTO for the summer of 2008 is projected to be 133,500 MW. For the summer of 2017, NID is projected to be 153,800 MW. The equivalent compound growth rate (ECGR) of the NID forecast is 1.6% from 2008 to 2017. This is the same as the ECGR 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 use of the load management placed under PJM coordination. The forecast is dated January 2008, and is based on economic data from late 2007.

Load Management placed under PJM coordination is PJM's program for Demand-Side Management (DSM). PJM identifies two types of DSM, Direct Control, and Interruptible. Direct control amounts to 400 MW with an additional 4,000 MW of Interruptible Demand. The analysis assumes the DSM remains constant in PJM throughout the assessment period.

The estimated Total Internal Demand (TID) of PJM RTO for the 2008 summer season is 137,900 MW and is forecast to increase to 158,200 MW by 2017. The ECGR of the 2008 TID forecast is 1.5%, which is slightly less than the 1.6% ECGR last year for 2007-2016.

MIDWEST ISO DEMAND DATA

The estimated Net Internal Demand (NID) peak of the entire Midwest ISO Market for the summer of 2008 is projected to be 100,000 MW. For the summer of 2017, NID is projected to be 114,500 MW. The equivalent compound growth rate (ECGR) of the NID forecast is 1.5% from 2008 to 2017. This is slightly higher than the 1.4% ECGR of last year's NID forecast. These values are based on the Total Internal Demand (TID) demand forecast developed for the MISO market. The forecast was developed early in 2008 from independent member forecasts. Each MISO member used applicable economic data from late 2007 during the development of their demand forecast.

MISO identifies two types of DSM, Direct Control and Interruptible, in the demand forecast. Direct control amounts to 1,700 MW with an additional 3,100 MW of Interruptible Demand in 2008. MISO has forecast an initial decline in DSM after 2008 with slow increase back to a total DSM forecast of 4,800 MW in 2017.

The estimated Total Internal Demand (TID) of MISO for the 2008 summer season is 104,800 MW and is forecast to increase to 119,300 MW by 2017. The ECGR of the 2008 TID forecast is about the same as the 2007 ECGR of 1.4%.

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 RFC areas of PJM and MISO are combined with the data from the Ohio Valley Electric Corporation (OVEC) to develop the RFC regional data. The RFC demand forecast also accounts for the expected demand diversity among these entities. RFC uses the minimum diversity from the past 5 years which is 2.0%.

The estimated Net Internal Demand (NID) peak of the entire RFC region for the summer of 2008 is projected to be 177,200 MW. For the summer of 2017, NID is projected to be 201,700 MW. The equivalent compound growth rate (ECGR) of the NID forecast is 1.5% from 2008 to 2017. This is slightly higher than the 1.4% ECGR of last year's NID forecast.

The DSM reported by PJM and MISO amounts to 900 MW of Direct Control Load Management with an additional 5,900 MW of Interruptible Demand in 2008. This increases to a total DSM forecast of 6,900 MW in 2017.

The TID for the summer of 2008 is projected to be 184,000 MW. For the summer of 2017, TID is projected to be 208,600 MW. The equivalent compound growth rate (ECGR) of the TID forecast is 1.4% from 2008 to 2017. This is the same as the 1.4% ECGR of last year's TID forecast.

Generation

The generating capacity in this assessment represents the rated capability of the generation in OVEC and in the PJM and MISO market areas. For this assessment this capacity is categorized as "existing", "planned", or "proposed". Customer generation or co-generation capacity is not included in this assessment when it only supplies power to local customer demand not included in the regional demand totals.

Existing capacity is either listed as "certain" or "uncertain". Certain capacity is a capacity resource cleared in PJM's Reliability Pricing Model (RPM) or a Designated Network Resource (DNR) in the MISO market. Uncertain resources are the existing generation that represents wind/variable resource de-ratings, generating capacity that has not been studied for delivery within the region, and capacity located within the region that is not part of PJM committed capacity or MISO DNR. Uncertain generation is not included when determining the reserve margins.

"Planned" capacity is future additions expected to go in-service in the respective years, and are used when determining the reserve margins. In this assessment, planned capacity is assumed to go in service as scheduled. "Proposed" capacity is less certain future capacity additions and only a portion of the total capacity is included when determining the expected reserve margins. Generation Interconnection queues are the sources of data for the planned and proposed generating unit additions. The amount (percentage) of proposed capacity additions to be included in the reserve margins is 20% for PJM and 31% for MISO.

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. When three years of operating data are not available for a specific wind project, that project substitutes a default capability for the unavailable data. PJM has recently changed the default wind capability from 20% to 13% for new queue projects. In MISO, wind power providers may declare up to 20% of nameplate capability as DNR. The difference between the nameplate rating and the expected wind capability is not included in the reserve calculations. In this assessment, Reliability*First* used 20% of nameplate rating for both PJM and MISO as the on-peak capability for planned and proposed wind power projects.

Generally, scheduled maintenance is minimized during the peak demand periods. This assessment assumes no scheduled maintenance during the summer periods. It is important to note that the capacity resources identified as "certain" in this assessment have been pre-certified by either PJM or MISO as able to be used within their RTO market area. This means that these resources are considered to be fully deliverable within and recallable by their respective markets.

The planned and proposed generation additions included in the reserve margin calculations for both PJM and MISO are assumed in this assessment to satisfy their respective deliverability requirements. In both RTOs there may be additional resources identified as uncertain that may be available to serve load, yet are not included in calculating the expected reserve margins in this assessment.

PJM GENERATION
The entire PJM RTO has 165,500 MW of existing "certain" generation for the 2008 summer. There is also 1,800 MW of existing capacity that is categorized as "uncertain" for the entire ten year assessment period. The increase in planned generation additions through 2017 is 4,400 MW. The amount of proposed increase in capability from the PJM generator interconnection queue is 49,500 MW. The confidence factor used by Reliability*First* to calculate the amount of proposed capacity to be included in the assessment of future reserve margins is 20% for PJM.

MISO GENERATION
The Midwest ISO market has 115,300 MW of existing "certain" generation for the 2008 summer. There is also 6,600 MW of existing capacity that is categorized as "uncertain" for the entire ten year assessment period. The increase in planned generation additions through 2017 is 4,400 MW. The amount of proposed increase in capability from the MISO generator interconnection queue is 25,200 MW. The confidence factor to be used to calculate the amount of proposed capacity to be included in the assessment of future reserve margins is 31% for MISO.

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 "certain" capacity in RFC is 213,700 MW. There is also 3,100 MW of existing capacity that is categorized as "uncertain" for the entire ten year assessment period. The increase in planned generation additions through 2017 is 5,800 MW. The amount of proposed increase in capability in the RFC region from the PJM and MISO generator interconnection queue is 47,200 MW. The confidence factor used by Reliability*First* in this assessment is 20% for PJM and 31% for MISO. The amount of proposed capacity that will be included in the assessment of future reserve margins will be based on these confidence factor percentages. Within Reliability*First* there is about 1,700 MW of existing nameplate wind turbine capacity with 200 MW being included as on peak capacity for reserve requirements. There is also approximately 700 MW of existing biomass type resources within the region.

Purchases and Sales

PJM and MISO have assumed for this assessment that the expected purchases and sales across their RTO boundaries will be the same for all years. These net transactions identified by PJM and MISO are considered firm transactions with firm transmission reservations and they will be included when determining the reserve margins in Reliability*First*. PJM and MISO only include firm transactions and less than 200 MW of the total transactions in MISO use Liquidated Damage Contracts. There are no Liquidated Damage Contracts in PJM.

Some of the total interchange reported by PJM and MISO is due to jointly owned generation. These resources are located in one RTO but have owners in both RTOs with entitlements to the generation. Also, some of the interchange in PJM and MISO comes from OVEC entitlements. Since the jointly owned generation and the OVEC generation is all within RFC, the jointly owned and OVEC generation is included in RFC's generation and not the RFC net interchange. Therefore, the total net interchange for the RFC region is not a simple summation of the PJM and MISO RTO interchange.

PJM NET INTERCHANGE
Transactions for the PJM RTO net to 1,500 MW of interchange out of the PJM RTO.

MISO NET INTERCHANGE
MISO has reported net interchange transactions (purchases) of 6,300 MW into the MISO market.

RFC NET INTERCHANGE
The net interchange transactions for OVEC, MISO and PJM at the time of the peak that cross the RFC regional boundary are projected to balance. Forecasts of future interchange transactions are very speculative, since they rely on generation resources that are in other regions. While the Reliability*First* believes significant power could be imported into the region when necessary, no import has been included in determining the future reserve margins.

Fuel

The fuel mix of generating units in the Reliability*First* region in 2008 is 15% nuclear, 3% hydro and pumped storage hydro, 47% coal, 8% oil, 26% gas, and 1% wind and other. Many factors can adversely impact fuel supply and delivery, and, therefore, adversely impact available generating capacity. However, these factors are usually the result of a local accident (train derailment), some naturally occurring event (heat wave or drought) or natural disaster (hurricane).

Recent events, such as the 2005 Gulf coast hurricanes and the Powder River Basin railroad derailment and subsequent repair and maintenance activities, provide evidence that today the gas supply and coal delivery networks are near their current limits. However, since these have typically been short term problems, Reliability*First* does not expect a fuel problem to affect the long term assessment.

Transmission

Plans within Reliability*First* for the next six years include the addition of over 1,600 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 serving load centers. MISO and PJM have identified many new projects as part of the Midwest ISO Expansion Plan (MTEP) and the PJM Regional Transmission Expansion Plan (RTEP). MISO projects can be referenced at http://www.midwestmarket.org/page/Expansion%20Planning.

Furthermore, there are several "backbone" transmission projects that are planned within Reliability*First*. PJM's 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/planning/reg-trans-exp-plan.html.

The Trans-Allegheny Interstate Line (TrAIL) project (see http://www.aptrailinfo.com/index.php) 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, DC area, including anticipated overloads expected in 2011 on the existing 500 kV network. The four-year 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 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 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)[171] 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, MD 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 DC 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, VA and terminating at Salem, NJ. See http://www.powerpathway.com/overview.html for more information.

In each of these four projects (TrAIL, Susquehanna to Roseland, PATH, and MAPP) PJM and its TO's are working in concert with local and state authorities to ensure project schedules are maintained. In the event that any one of these projects is delayed, short-term operating procedures will be used to mitigate any problems. However, in the longer term, the most reliable solution is the construction of the project.

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.

[171] http://www.pathtransmission.com/overview/default.asp

Additionally, AEP and Duke have recently announced a joint venture, Pioneer Transmission LLC, to build 240 miles of 765 kV transmission line and related facilities in Indiana from the Rockport to Greentown stations. The project will be submitted later this year to both MISO and PJM for consideration in their MTEP and RTEP expansion plans, respectively. The earliest possible in-service date could be 2014 or 2015, depending upon all of the necessary approval processes. See http://www.nrel.gov/wind/systemsintegration/news/2008/628.html for more information.

Phase Angle Regulators (PARs) are located on all major ties between northeastern PJM and southeastern New York to help control unscheduled power flows. The Ramapo PARs in NPCC control flow from RFC to NPCC. The Michigan-Ontario PARs have not yet achieved long-term operation of all four units. The B3N PAR in Michigan that previously failed will still be out-of-service until the summer of 2010, and the remaining three PARs are expected to control flows (i.e. will be regulating). An operations agreement for controlling the interface has been completed. In this assessment, all four of the PARs on the Michigan-Ontario border are regulating and the base flows in Pennsylvania have changed compared to the summer of 2008. Transmission Planners will need to address this accordingly.

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.

Certain critical flow-gates that have experienced TLRs in previous summers continue to be identified as heavily loaded in various reliability assessments and may require operator intervention to ensure reliability is maintained.

The transmission system is expected to perform well over a wide range of operating conditions, provided that new facilities go into service as scheduled, and that 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.

Reliability Assessment Analysis

The Reliability*First* Long Term assessment uses the reserve margin targets determined for the PJM and MISO areas to assess the expected adequacy of generation resources over the next ten years. Analyses were conducted by PJM and the Midwest PRSG around the end of 2007 and early in 2008 to determine the reserve margins that were equivalent to the Reliability*First* Loss of Load Expectation (LOLE) criterion of not exceeding one occurrence in ten years on an annual basis. These analyses include demand forecast uncertainty, outage schedules, and other relevant factors when determining the probability of forced outages exceeding the available margin for contingencies. Reliability*First*'s assessment of long term PJM resource adequacy is based on the reserve margin target determined from the PJM Reliability Pricing Model (RPM) analysis for planning year 2008-2009. This reserve margin target is 15.0% through 2012 and 15.5% for later years. To assess long term MISO resource adequacy, RFC calculated a combined reserve margin target for the 2008-2009 planning year of 14.1%. This reserve margin was based on the reserve requirement for demand in the Midwest PRSG, the remaining MRO area of MISO that uses the MAPP reserve requirement, and the small amount of other MISO demand that uses the MISO default reserve requirement.

This assessment evaluates the adequacy of the capacity in the each RTO and the region to supply the demand in each RTO and the region, respectively. The reserve margin targets of each RTO were weight-averaged together to develop a reserve margin target to use to gauge the general adequacy for the RFC region. This combined reserve margin target for the RFC region is 14.7%. Although Reliability*First* determines seasonal resource adequacy from the assessments of the two RTOs, in the long term assessment there is more variation and uncertainty in future resources. Therefore, Reliability*First* uses this reserve margin target to review the reserve margin forecast of the regional area for the assessment period against a combined reserve margin target for each year in the analysis period, in addition to the review of the RTO reserve margins and reserve margin targets.

As previously mentioned in the Generation section, uncertain resources are not included in the calculation of expected reserve margins. Energy-only, existing wind deratings and any transmission limited resources are considered uncertain in this analysis, and therefore is not included. Future planned capacity changes that are factored into the expected reserves include rating changes of existing generation, new generation, and known planned retirements of existing generation.

Deliverability of capacity between the RTOs is not addressed in this report. However, each of the LOLE studies conducted to determine the target reserve margins used in this assessment has assumed limited or no transfer capability between these RTOs. By limiting the transfers between PJM and MISO in this assessment, the reserve margin target for the Reliability*First* region will be somewhat more conservative than a target determine by including the full inter-RTO transfer capability.

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. Operational measures that would be expected to be deployed to mitigate adverse conditions during this assessment period are the same as those discussed on page 94 of the Reliability*First* section of NERC's "*2008 Summer Reliability Assessment*".

PJM RESERVE MARGINS

The reserve margin for existing capacity resources is 30,500 MW in PJM for 2008, which is 22.8% based on NID. With an additional 4,256 MW of planned new capacity, the reserve margins are expected to meet the 15.0% reserve margin target through 2013. The target increases to 15.5% after that time. Additional resources will be needed beyond 2013. The amount of proposed resources needed in this assessment starts at 1,600 MW in 2013 and increases to about 9,100 MW by 2017. This is 18.4% of the 49,500 MW of resources in the PJM generator interconnection queue that was categorized as proposed resources.

It should be noted that PJM has assumed a constant 1,500 MW export over the assessment period. If there were no net interchange for the RTO, there would only be a need for 7,600 MW of additional proposed resources.

MISO RESERVE MARGINS

The reserve margin for existing capacity resources is 21,500 MW in MISO for 2008, which is 21.5% based on NID. With an additional 4,400 MW of planned new capacity, the reserve margins are expected to meet the 14.1% target through 2014. Additional resources will be needed beyond 2015. The amount of proposed resources needed in this assessment starts at 1,300 MW in 2015 and increases to about 4,600 MW by 2017. This is about 18.0% percent of the proposed resources in the MISO generator interconnection queue.

It should be noted that MISO has assumed a constant 6,300 MW import over the assessment period. If there were no net interchange for the RTO, there would a need for 10,900 MW of additional proposed resources by 2017.

RFC RESERVE MARGINS

The reserve margin for existing capacity resources is 36,600 MW in Reliability*First* for 2008, which is 20.6% based on NID. With an additional 5,700 MW of planned new capacity located within the region, the reserve margins are expected to meet the 14.7% target through 2012. Additional resources will be needed beyond 2012. In 2013, there will be a need for less than 300 MW of proposed resources. The amount of proposed resources will increase to about 11,800 MW by 2017. This represents 25.0% of the combined PJM and MISO proposed generator resources in the Reliability*First* area.

Both MISO and PJM conduct comprehensive detailed generator load deliverability studies. MISO deliverability (http://www.midwestmarket.org/page/Generator+Interconnection) test results can be found under Generator Deliverability Tests. For more information on PJM deliverability (http://www.pjm.com/contributions/pjm-manuals/pdf/m14b.pdf), see Appendix E of the PJM Manual 14b. 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/teac/teac.html for more details. Neither MISO nor PJM have any deliverability concerns for this assessment period.

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/planning/rtep-baseline-reports/baseline-report.html). Small signal analysis is performed as part of long-term studies, but not for seasonal assessments. MISO also performs transient stability analysis.

The Cleveland area was shown to be a reactive power-constrained area from the 2003 blackout. However, several actions have been taken to mitigate any 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 two automatic under voltage load shed (UVLS) schemes within RFC. One is located in the northern Ohio/western Pennsylvania area and the other is in the northern Illinois area. These schemes have the capability to automatically shed a combined total of about 2,300 MW and provide an effective method to prevent uncontrolled loss-of-load following extreme outages in those areas. There are currently no new plans to install UVLS within the RFC region.

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* does plan to conduct some NERC Category D contingency analysis as part of the long-term transmission assessment study later this year.

Areas within Reliability*First* are currently not experiencing drought conditions.

All Transmission Planners within Reliability*First* conduct studies, as required in the NERC TPL Standards. Reliability*First* also conducts regional studies that include NERC Category A, B, and C contingencies. Results of these studies are used in the regional assessment reports. Extensive contingency analysis is performed by PJM as part of the RTEP analysis, which includes transient stability analysis. Details can be found at http://www.pjm.com/committees/teac/teac.html. MISO also performs contingency analysis as part of their MTEP studies.

Reliability*First* is not currently aware of any new technologies that will be deployed within the region to improve bulk-power system reliability.

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 nor is aware of any program to share inventory of spare equipment. The legacy Regions had previously participated in providing information to the NERC spare transformer database.

Other Region-Specific Issues

In December 2007, the Maryland Public Service Commission (PSC) issued a first in a series of Interim Reports regarding the state of the electricity markets in Maryland. As directed in Maryland Senate Bill 400, the report offers the PSC's recommendations and analysis regarding options for "re-regulating" Maryland's electricity markets and for obtaining new generation and transmission resources in the state. The premise for the analysis is the PSC's view that "unless steps are taken now, the State of Maryland may face a critical shortage of in-state electricity capacity that could force mandatory use restrictions, such as rolling black-outs, by 2011 or 2012".

The options considered in the PSC's analysis include full re-regulation, mandatory utility-directed long-term contracts, establishing a State Power Authority, reinstitution of integrated resource planning and aggressive efforts to shape PJM's wholesale markets. The PSC recommended a series of interventions designed to (begin to) address Maryland's perceived reliability problem that could include forcing an increase in the available supply of electricity and requiring utilities to implement aggressive and cost-effective demand management and energy conservations programs For more information, see the Maryland PSC web site at http://www.psc.state.md.us/psc/Reports/2007SupplyAdequacyReport_01172007.pdf

One method that addresses the aging workforce issue is FirstEnergy's Power Systems Institute (PSI), which has teamed with several local community colleges and universities to offer Associate Degree programs that lead to careers in skilled technical fields. These unique, two-year programs combine classroom learning with the hands-on training needed to open the door to opportunities as line, substation, plant or nuclear workers in the electric utility industry. For information, see http://www.firstenergycorp.com/career_center/technical_training/index.html.

Reliability*First* has no additional reliability concerns for this long-term assessment.

Region Description

ReliabilityFirst currently consists of 44 Regular Members, 23 Associate Members, and 4 Adjunct Members operating within 12 NERC balancing authorities, which includes over 360 owners, users, and operators of the bulk-power system. They serve the electrical requirements of more than 72 million people in a 240,000 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 ReliabilityFirst area demand is primarily summer peaking. Additional details are available on the ReliabilityFirst website (http://www.rfirst.org).

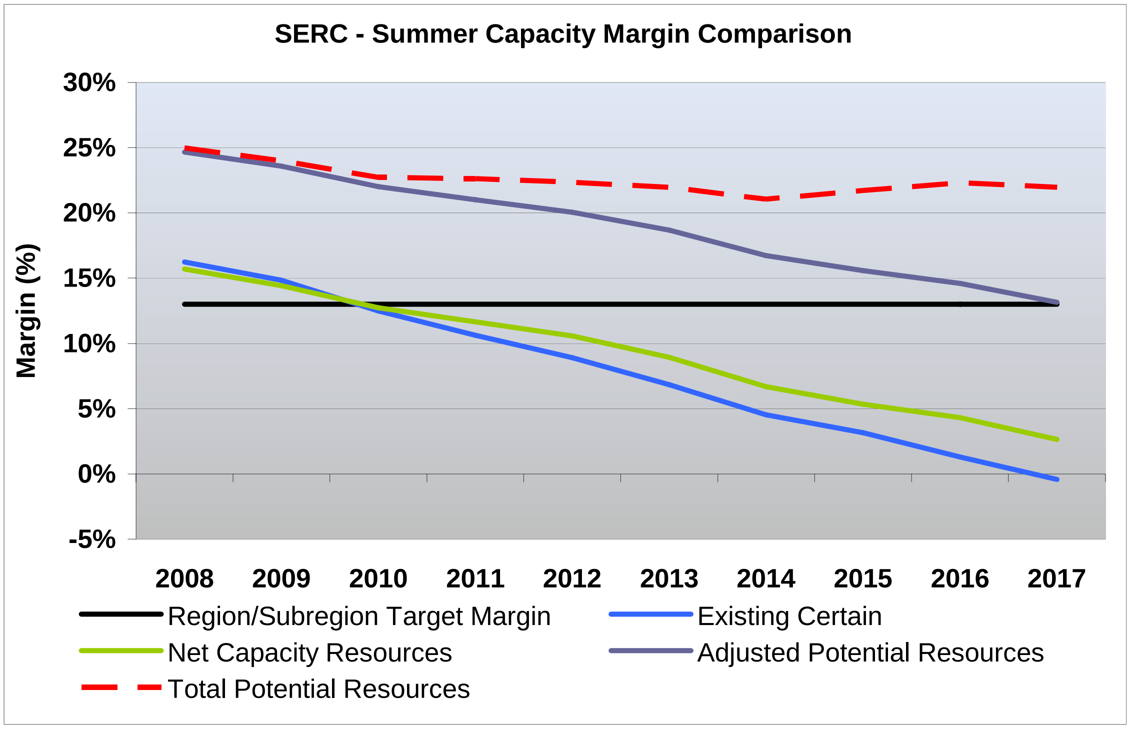
SERC Highlights

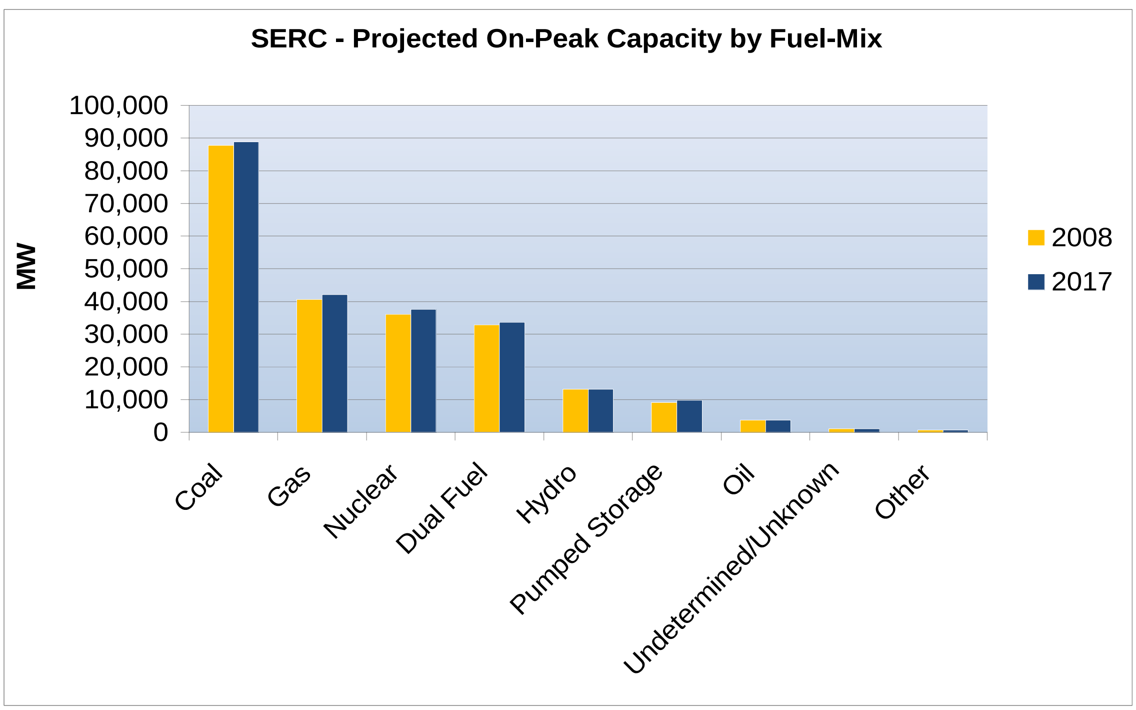
SERC members project that resources in the region will be adequate to meet demand over the forecast period provided there is regulatory support on a state and local level for the development of needed generation. Although the SERC region does not implement a regional reserve requirement, SERC members adhere to their respective state commissions' regulations or internal business practices as they plan for or procure resources.

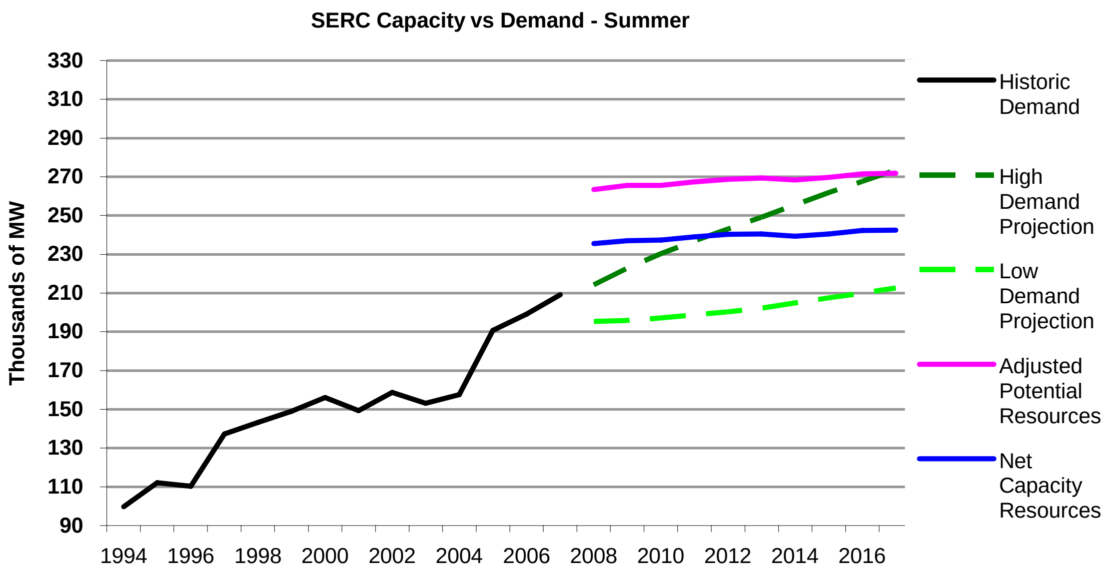
Significant generation development has occurred in the SERC region during the past few years, resulting in thousands of MW of non-committed generating capacity being installed without a specific allocation to load. Some of this generation can be made available as short-term, non-firm or potential future resources to SERC members and others if deliverability is ensured. Some of this generation went unreported under the new NERC definitions used for capacity analysis in this LTRA. This reporting issue is expected to be remedied in future reports. It is estimated that some 28,000 MW went unreported. In this LTRA SERC has reported the details of its Annual Generation Development Survey, which is independent of the NERC effort, in order to present a more complete picture of potential resources.

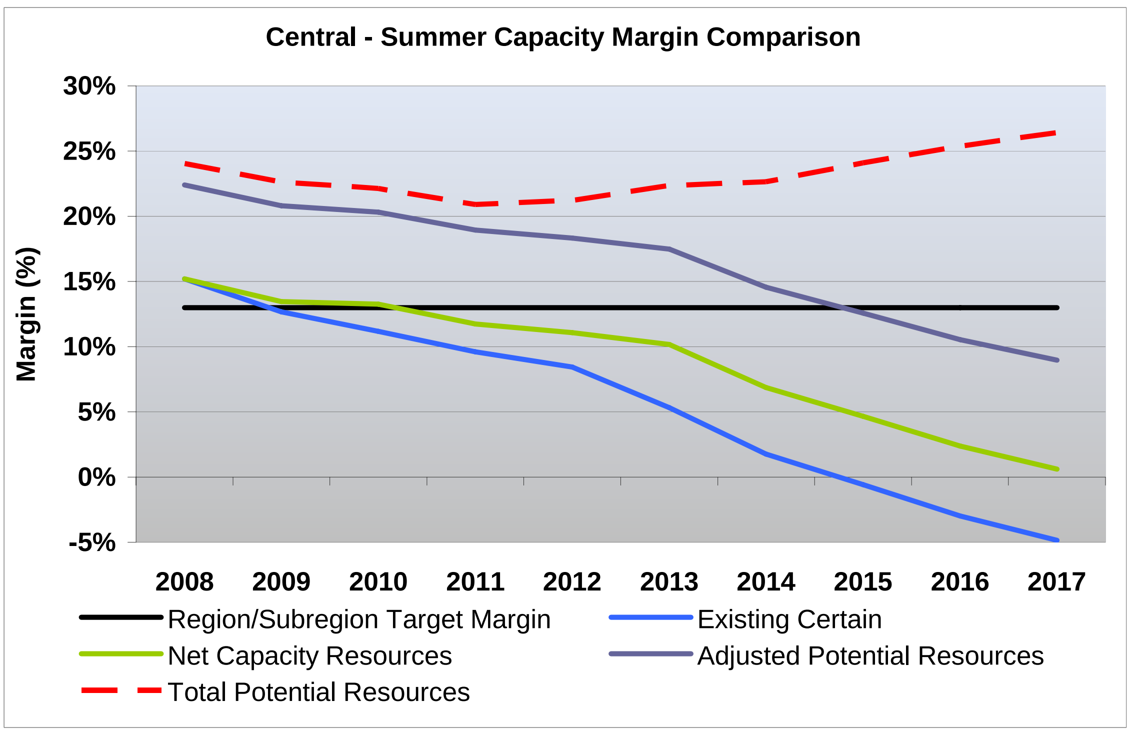
SERC members participate in numerous transmission assessment processes. The individual transmission owners within SERC conduct assessment studies to ensure compliance of their individual system which are subsequently subject to audits and assessments by SERC. Some subregions (like VACAR) conduct assessment studies of the entire subregion to ensure simultaneous compliance of the systems within the subregion. Further, SERC has study groups that conduct assessment studies of the entire region to ensure simultaneous compliance of all the systems within the region.

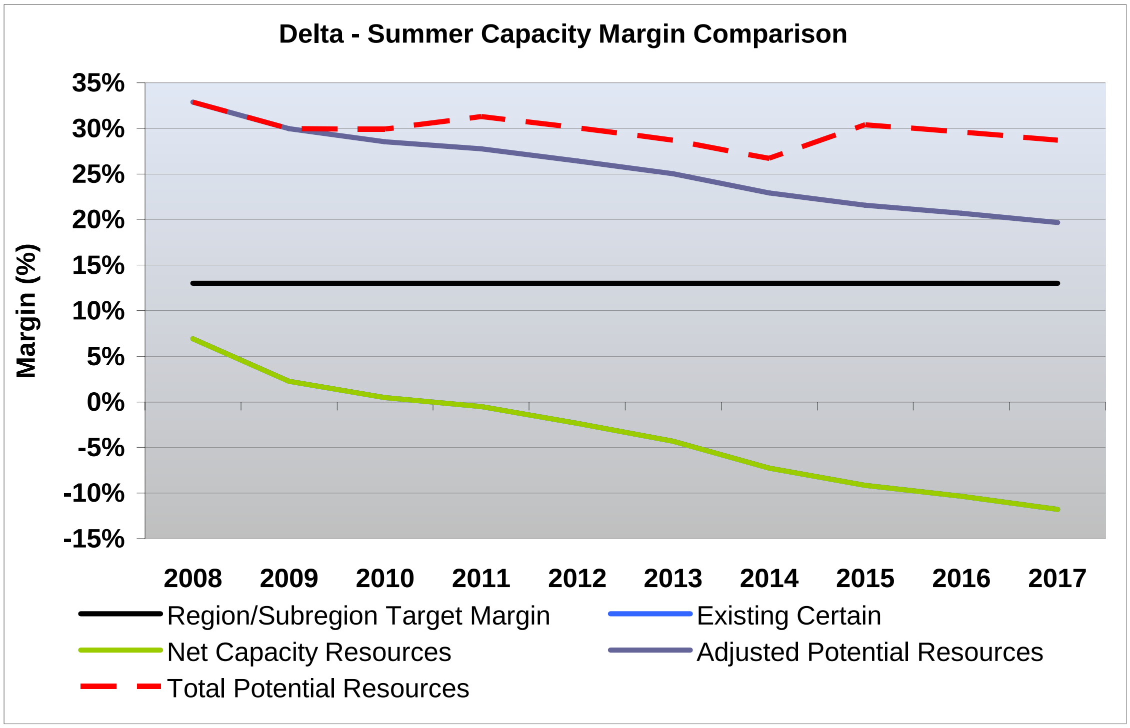
In preparation for summer 2008 SERC members conducted a special drought assessment considering a hydrological scenario more severe than the forecast 2008 summer conditions. The study projects that there will be no major reliability issues under the severe case tested in the study. At the present time, (Fall 2008) conditions are improving in many (but not all) of the drought-affected areas. The study also provided valuable experience for managing drought situations as they arise in the future.

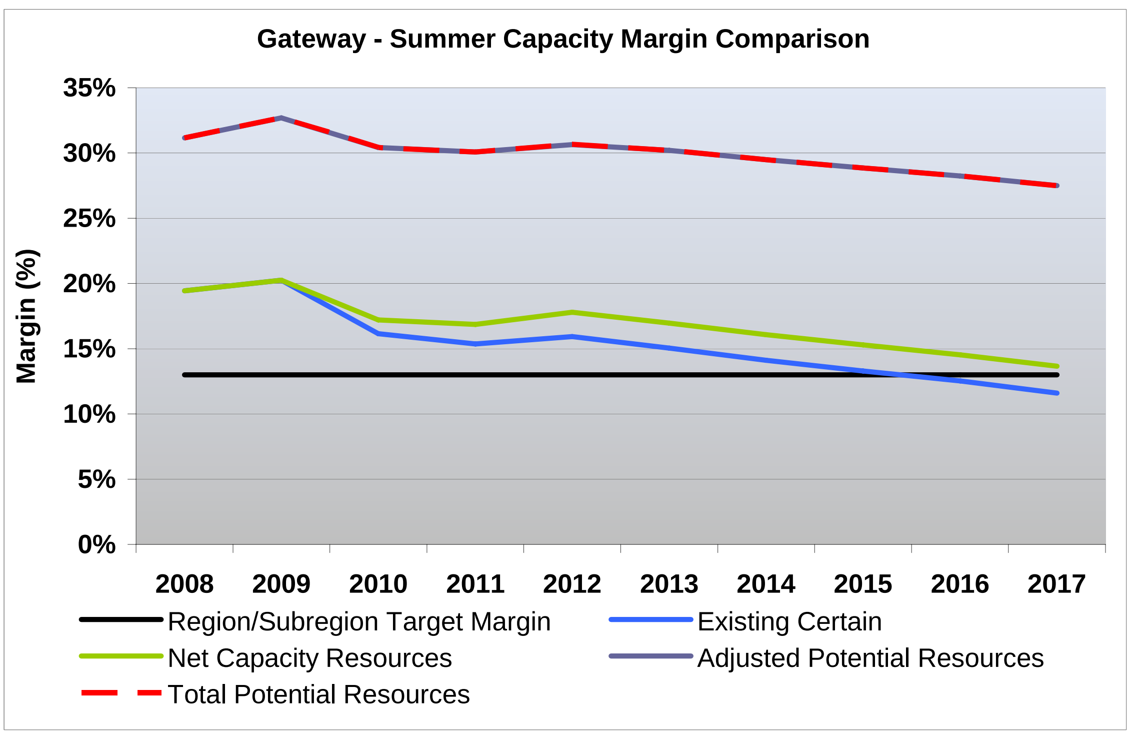

SERC - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

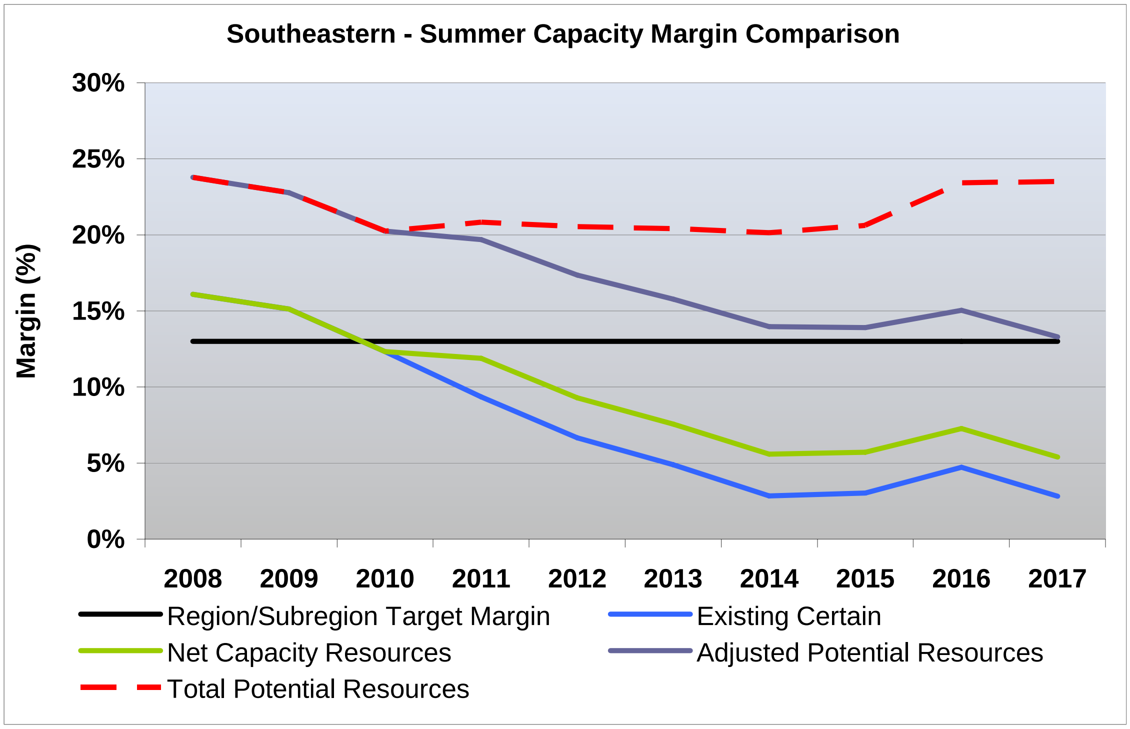

SERC - Projected On-Peak Capacity by Fuel-Mix
MW
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Coal
Gas
Nuclear
Dual Fuel
Hydro
Pumped Storage
Oil
Undetermined/Unknown
Other
2008
2017

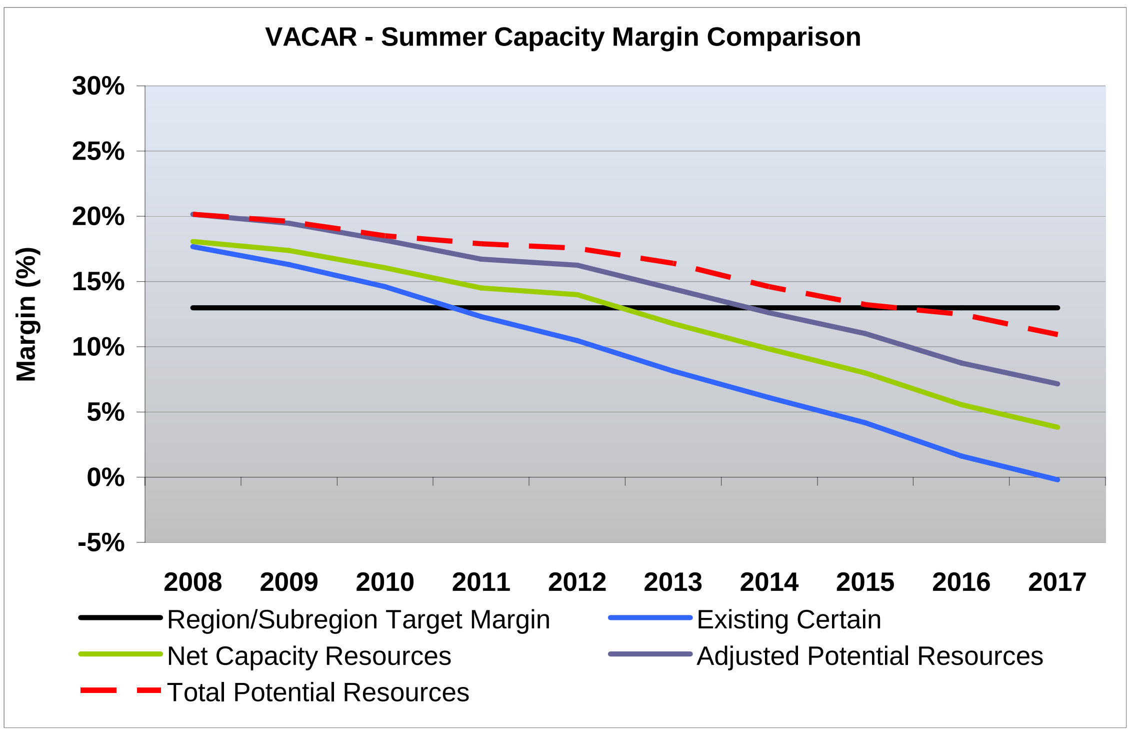

SERC Capacity vs Demand - Summer
Thousands of MW
330
310
290
270
250
230
210
190
170
150
130
110
90
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources


Central - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


Delta - Summer Capacity Margin Comparison
Margin (%)
35%
30%
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


Gateway - Summer Capacity Margin Comparison
Margin (%)
35%
30%
25%
20%
15%
10%
5%
0%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


Southeastern - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


VACAR - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

SERC Self-Assessment

Introduction

The SERC Reliability Corporation (SERC) is the Regional Reliability Organization (RRO) for all or portions of 16 central and southeastern states. SERC is divided into five sub-regions: Central, Delta, Gateway, Southeastern, and VACAR, that together supply power to approximately 23% of the electric customers in the United States. Most electric utilities within SERC have traditional vertically integrated corporate structures with planning philosophies based on an obligation to serve ensuring that designated generation operates under optimal economic dispatch to serve local area customers. A few SERC members, however, have selected or 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 that manages transmission flows to customers over a broader regional area through congestion-based locational marginal pricing. Companies within SERC are closely interconnected and the region has operated with high reliability for many years.

It should be noted that the generation capacity figures provided here are based generally on the data submitted for the current EIA 411 report. In addition to the collection of data from members in accordance with NERC's prescribed definitions, SERC collects generation data for the forecast period from its members. This data focuses on generation which is constructed, but not necessarily dedicated or committed to serving load. Such generation performs a merchant function, operating when it is economic to do so. Even though a significant amount of merchant generation has been developed within SERC in recent years, not all of that generation is reflected in the capacity margins is presented here. It is estimated that there is presently nearly 28,000 MW of such generation in the SERC region that is in addition to what is reported in the EIA 411 report.

Capacity resources in the region as a whole are expected to be adequate to reliably supply the forecast firm peak demand and energy requirements throughout the long-term assessment period. Reported potential capacity additions and existing capacity, including uncommitted resources, along with the necessary transmission system upgrades, could satisfy capacity margin needs through 2017. 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 that influence the development of new generating resources.

The SERC region has extensive transmission interconnections between its sub-regions and its 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 $1.262 billion in transmission system upgrades 100 kV and above in 2007, plan to invest approximately $1.631 billion in 2008 and are planning transmission capital expenditures of more than $8.66 billion over the next five years. Planned transmission additions over the next ten years include 1,644 miles of 230-kV lines, 338 miles of 345-kV lines, and 447 miles of 500-kV lines.

Demand

The 2008 summer net internal demand forecast is 198,522 MW and the forecast for 2017 is 236,070 MW. The average annual growth rate over the next ten years is 1.94%. This is the same as last year's forecast growth rate of 1.94%. The historical growth rate of actual peaks has averaged 2.45% over the last 8 years.

All reported demands are non-coincident. These forecasts are based on average historical peak period weather conditions. There were no significant changes in weather or economic assumptions since last year's forecast.

The SERC region has 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 6,269 MW in 2008 to 6,986 MW in 2017. These amounts are higher than last year's projections due, in part, to the addition of new members. Also, a change in reporting philosophy regarding demand response programs within certain companies resulted in the additional increase in interruptible demand and demand-side management. However, an offsetting adjustment was made to the demand reported, resulting in no net change. In addition to the reported interruptible demand and load management, there are significant other demand-side management programs that are also available to maintain reliability in the region.

Temperatures that are higher or lower than normal and the degree to which interruptible demand and demand-side management is used can result in actual peak demands that vary considerably from the reported forecast peak demand. Although SERC does not perform extreme weather or load sensitivity analyses at the region level to account for this, SERC members address these issues in a number of ways, considering all NERC, SERC, regulatory, and other requirements. These member methods must be documented and are subject to audit by SERC.

While member methods vary to account for differences in system characteristics, the methods 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 such considerations as high and low economic scenarios and mild and severe weather; and
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies utilizing these forecasts.

In addition, many SERC members use sophisticated, industry accepted methods to evaluate load sensitivities in the development of load forecasts.

Regarding the influence of extreme weather, the 90th percentile peak temperature relates to an estimated extreme weather peak of about 6% higher than the regular forecast for the region. An extreme peak for 2008 summer equates to 210,433 MW of firm peak demand for the region. The capacity margin for this scenario is estimated to be 10.6%, which, although reduced from the expected margin under normal forecast conditions, remains at an adequate level for the extreme case condition. This analysis assumes the load response to temperatures in this extreme range is linear. However, there is insufficient historical evidence to support this, since at some point load saturation occurs as temperatures rise into extreme levels. Therefore the capacity margin is likely to be higher even under this extreme case. Since capacity margins for SERC are fairly constant for the 10-year period, this 2007 summer example can be used to conclude that extreme weather is not expected to reduce resource adequacy to critical levels. The SERC region as a whole is not expected to have any difficulty serving customers in a 90/10 outcome relative to the ten year load forecast.

Generation

SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands throughout the long-term assessment period. Reported potential capacity additions and existing capacity, including uncommitted resources, along with the necessary transmission system upgrades, could satisfy capacity margin through 2017. As can be seen in Figure 2, 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 siting process regulations that influence the development of new generating resources.

The changes in definitions established by the NERC Planning Committee have resulted in a significant change in both the reported generation for the 2008 LTRA and the generation included in the capacity margin calculation. SERC is presenting both the NERC and SERC results in this report.

SERC has had significant merchant generation development which is not included in the NERC margin calculation. SERC member responses to the annual SERC Reliability Review Subcommittee's (RRS) Generation Plant Development Survey indicate nearly 28,000 MW of un-contracted merchant generation is connected to the member systems. This merchant generation has not been contracted to serve load within SERC and its deliverability is not assured. For these reasons, only merchant generation expected to serve SERC load is included in the capacity margins reported for SERC. A significant amount of merchant capacity within the region has been participating in the short-term energy markets, indicating that a portion of these resources are deliverable during certain system conditions. SERC's Generation Plant Development Survey is a summer capacity survey and does not distinguish winter ratings. If a load serving entity has a contractual arrangement with a merchant plant and has reported the arrangement through the EIA-411 reporting process, then this capacity is included in this capacity margin assessment. Because significant capacity exists in the region, there will continue to be additional generation above that which is reported in the capacity margin trend. NERC's capacity margin calculations also assume the use of load management and interruptible contracts at the time of the annual peak.

Although the SERC region does not implement a regional planning reserve requirement, members adhere to their respective state commissions' regulations or internal business practices as they plan for adequate generation resources. SERC members use various methods[172] to ensure adequate resources are available and deliverable to the load.

Resources are expected to be adequate even if resource unavailability is higher than expected since SERC entities recognize that planning for variability in resource availability is necessary. Many SERC members manage this variability through reserve margins, demand side management 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.

The projected 2008 capacity mix reported for SERC is approximately 37% coal, 15.2% nuclear, 9.4% hydro/pumped storage, 33% gas and/or oil, and 5.4% for purchases and miscellaneous other capacity. The mix has not changed significantly from last year. Generation with coal and nuclear fuels continues to lead the region's fuel mix, accounting for roughly 52.2% of net operable capacity in 2008.

The majority of planned capacity additions, as reported by member systems in the EIA-411 filings, is comprised of gas/oil fueled combustion turbine or combined cycle units. However, there are recent announced additions and plans in the ten-year planning horizon for coal-fired and nuclear plant additions.

Some examples are:

Potential Additions:

- Central Sub-region: 750 MW coal addition in 2010; 1,182 nuclear in 2012
- Delta Sub-region: Up to 3,102 of nuclear additions in 2015
- Gateway Sub-region: 1,650 MW merchant coal plant in 2011-2012; 1,650 MW nuclear addition in 2017
- Southeastern Sub-region: 1,200 MW merchant coal plant in 2012; 1,100 MW nuclear addition in 2016; 1,100 MW nuclear addition in 2017
- VACAR Sub-region: 620 MW coal addition in 2008-09, 800 MW coal addition in 2012, 605 MW coal addition in 2012-13, 1,100 MW nuclear addition in 2016

Of the approximately 7,657 MW of planned resource additions reported for the 2008-2017 time period, 7.94% are combined cycle, 26.71% are combustion turbine, 30.66% are steam (including nuclear), 26.41% are net purchases, .43% are hydro, 7.84% are pumped storage and .01% are

[172] Members have a variety of approaches to determining resource adequacy. These range from LOLE/LOLP on a company basis to target margin criteria. Some state jurisdictions in SERC have implemented specific requirements for some of SERC's members. SERC is in the process of reviewing the methods used by its members.

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.

Generation Development in SERC

Generation facilities need to be planned and constructed to ensure that aggregate generation capacity keeps pace with the electric demand. Generation reserve capacity must remain sufficient to mitigate postulated grid contingency scenarios. A growing number of independent power generating units are interconnecting to the grid and selling their product into the electricity market. While mechanisms exist at state and federal agencies to collect data about the interconnection of new facilities, it is often difficult to accurately capture all of the generation facilities in their various phases of development. The ability to rapidly install peaking capacity resources and a general trend toward seasonal and short-term capacity purchases further complicate data collection as many utilities are delaying firm purchase commitments as long as possible. There are, however, generating plants under development and uncommitted generating facilities already in service in SERC that have the potential to provide significant resources for certain individual members. The single best source of information regarding generation development in the SERC region remains the annual Generation Plant Development Survey.

To better understand the role that new generation facilities may play in serving the demand requirements of the SERC region, the SERC Engineering Committee authorized the SERC RRS in 1999 to conduct its first Generation Plant Development Survey. The tenth such survey was conducted in February 2008. The survey was directed to the transmission owners or providers within SERC. It was expected that these entities would be the best source of information for this survey because generation plant developers must coordinate with transmission owners or providers in accordance with FERC requirements prior to interconnecting to the transmission network.

Survey respondents were asked to report all generation development connected to the transmission systems within SERC, whether uncommitted or dedicated to serve native load. Projects were reported according to their stage of development as measured by the level of Interconnection Service requested and whether the generation will be designated as a network or native load resource (if known). The level of Interconnection Service is measured by two categories:

1) Interconnection Service that has been requested through the OASIS process, or
2) Interconnection Service Agreements that have been signed or unexecuted agreements that have been filed at FERC.

The 2008 survey focused not only on the growth of the generation resources within the region, but also provides a more accurate representation of future generation resources that considers retirements, total uncommitted resources, and inoperable uncommitted resources. A summary of the 2008 Generation Plant Development Survey results is provided in Table 1.

Table 1: Current Status of Generation Plant Development

Current Status of Generation Plant Development	In-Service Year of Added Generation (MW)										
CATEGORY	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**10 Yr Total**
1) Interconnection Service Requested, Only	65	2766	4945	10059	3336	5159	663	3248	2735	3169	**36144**
> Designated as Network Resource or has obtained Firm PTP Transmission service	33	2289	1851	3424	747	2788	663	3132	2735	1403	**19065**
> Uncommitted	32	477	3094	6635	2589	2371	0	116	0	1766	**17079**
2) Interconnection Agreement Signed/Filed	2327	2236	3597	3334	1807	207	110	500	864	250	**15231**
> Designated as Network Resource or has obtained Firm PTP Transmission service	2156	2078	1691	869	1192	116	110	500	864	250	**9825**
> Uncommitted	171	158	1906	2465	615	91	0	0	0	0	**5406**
3) Unit Retirements	78	0	114	75	198	276	235	486	133	133	**1728**
Net Projected Additions (1) + (2) – (3)	**2314**	**5002**	**8428**	**13318**	**4945**	**5090**	**539**	**3262**	**3466**	**3286**	**49647**

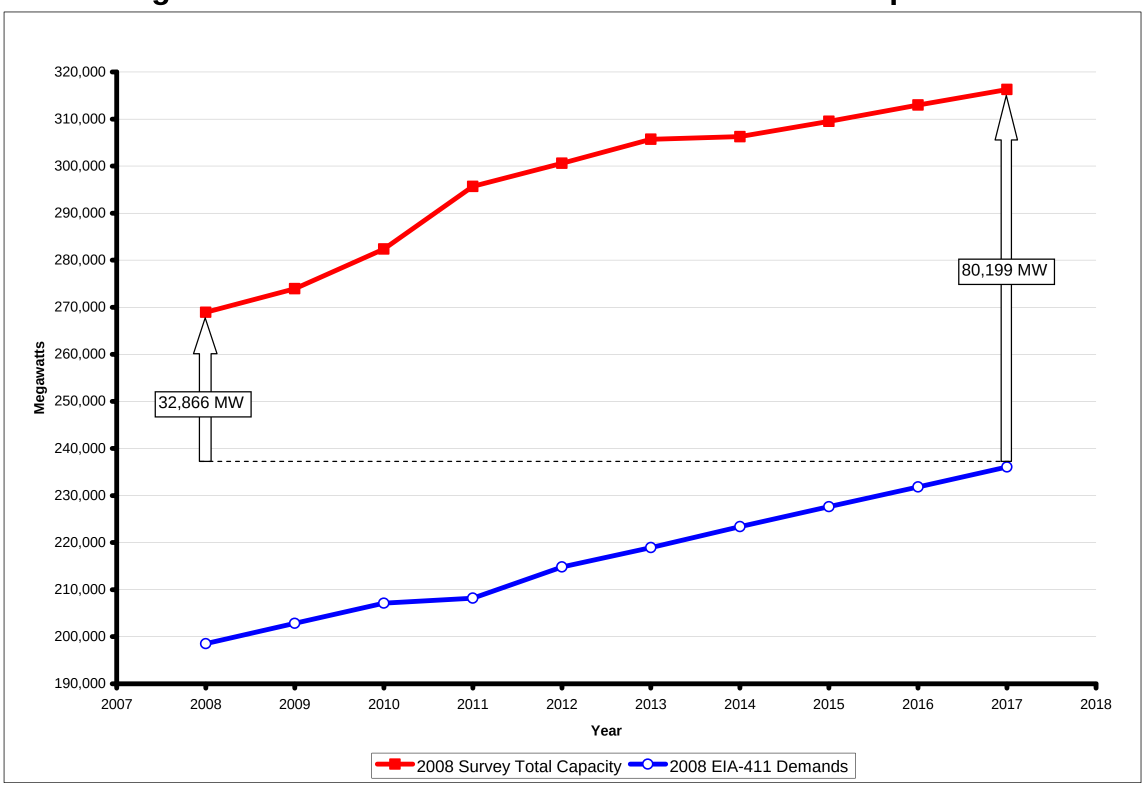
*Source — SERC Reliability Review Subcommittee 2008 report to the SERC Engineering Committee

The survey indicates an additional 2,392 MW of generation plant capacity is expected in the SERC region for the 2008 summer, with 78 MW of retirements scheduled, resulting in net potential additions of 2,314 MW. The vast majority of additions had signed or filed interconnection agreements at the time of the survey. In the near-term planning horizon (2008-2013) there is significant speculation about the amount of generation that will be added (approximately 39,800 MW, of which over 26,300 MW falls in category 1), and its impact on the capacity margin for the region. Also, a significant number of wind generators (over 3,900 MW) have requested interconnection service in the Gateway sub-region in this time period. The trend from last year's survey to this year's indicates that there is more uncertainty regarding near-term generation resources, since near-term Category 1 additions outnumber those in Category 2, but the amount reported to be constructed will likely change before the next annual survey.

Category 2 additions are significantly smaller in the longer-term (2008-2017). However, the more speculative Category 1 additions are higher throughout the 10-year period. This pattern is not unexpected since plans for the longer-term continue to undergo review and revisions. The 39,800 MW of generation development reported in the first six years of this year's survey is significantly higher than the 28,100 MW reported in last year's survey. The majority of the increase is due to Category 1 additions in the VACAR sub-region. The amount of the reported planned capacity that will actually be built is highly dependent on factors such as regulatory approvals, market prices, fuel availability, the ability to arrange suitable interconnection and transmission access agreements, the number of other generation plants that are being constructed, the ability to permit and complete necessary transmission line additions in a reasonable amount of time, the ability of the generation developer to obtain financial backing, and other typical business factors.

The horizontal line in Figure SERC-1 demonstrates that the SERC region has 32,866 MWs more generation within the region in 2008 than will be required to meet the region's demand in 2017. Total potential generating plant capability for July 1, 2013 from the 2008 survey is 305,717 MW, versus the 288,137 MW that was identified for that time period in the 2007 survey. Over the period covered by the 2008 survey, generation capacity additions totaled 49,647 MW versus 44,463 MW reported in 2007 for the period covered by that survey. This marks the third consecutive survey with increased potential capacity additions. The SERC RRS believes that the Generation Plant Development Survey provides one important indication of the potential generation development within the SERC region and its sub-regions.

Figure SERC-1: Potential Generation Plant Development in SERC



*Source — SERC Reliability Review Subcommittee 2008 Generation Plant Development Survey

Purchases and Sales

Near-term (2008-2013) planned firm purchases across the SERC electrical borders total 1,548 MW and are comprised of 908 MW from RFC and 640 MW from SPP. These firm purchases have been included in the capacity margin calculations for the region.

Near-term planned firm sales across the SERC electrical borders total 3,186 MW and are comprised of 1,551 MW to FRCC, 1,247 MW to RFC, 13 MW to MRO, and 375 MW to SPP. These firm sales have been accounted for in the capacity margin calculations for the region.

In the long-term (2008 to 2017), purchases and sales are difficult to forecast with any certainty. Purchases declined from 1,553 MW to 780 MW. Sales declined from 3,363 MW to 676 MW. Only firm transactions are accounted for in the capacity margin calculations for the region.

Fuel

Fuel supplies are expected to be adequate to meet forecast demands over the next 10 years. Sufficient inventories (including access to salt-dome natural gas storage), fuel-switching capabilities, alternate fuel delivery routes and suppliers, and emergency fuel delivery contracts are some of the important measures used by SERC members to reduce reliability risks due to fuel supply issues. The predominant fuel type used in the region is coal, and its share of member's capacity is 37.3% of the total generation. Gas generation is used during peaking conditions and its reported share of member's capacity is 16.6% of total generation.

SERC members recognize that planning for variability in resource availability is necessary. Many SERC members typically provide for this variability through capacity margins, demand side management 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. Emergency sales and purchases and activation of shared reserves have been used in the region during the past year. However, the frequency of their use has not increased relative to previous years.

Fuel supply will always be a critical part of the power supply chain, regardless of fuel choice. SERC utilities have been able to maintain fuel diversity in their portfolios, enhancing reliability. Looking forward, SERC is following these issues to ensure reliability is maintained into the longer-term planning horizon:

- Protecting the nation's natural gas production and transportation facilities in the Gulf Coast areas
- Monitoring the development of LNG facilities in both the U.S. and other natural gas producing countries
- Monitoring the next wave of new generation additions over the next 10 - 15 years
- Ensuring that the coal delivery infrastructure keeps pace with the forecasted increase in construction of coal generation facilities
- Ensuring that fuel inventories continue to be managed appropriately to mitigate the effects of natural disasters and other causes of disruptions to fuel supplies

Transmission

The existing bulk transmission system within SERC totals 49,994 miles of transmission lines comprised of 17,699 miles of 161-kV, 20,447 miles of 230-kV, 3,246 miles of 345-kV, and 8,602 miles of 500-kV transmission lines. SERC member systems continue to plan for a reliable bulk transmission system and plan to add 317 miles of 161-kV, 1,644 miles of 230-kV, 338 miles of 345-kV, and 447 miles of 500-kV transmission lines in the 2008–2017 time period. As reported in the 2007-2016 NERC LTRA Report, the bulk transmission expansion plans of SERC region members are second only to the WECC. Furthermore, the planned transmission expansion in SERC represents approximately 20% of all transmission expansion in the U.S. over the next ten years. This marks the sixth consecutive year in which SERC has reported at least one-fifth of all planned U.S. transmission expansion. SERC members invested $1.262 billion in new transmission lines and system upgrades in 2007 (includes transmission lines 100 kV and above and transmission substations with a low-side voltage of 100 kV and above), and are planning transmission capital expenditures in excess of $8.66 billion over the next five years.

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 inter-regional studies help to demonstrate that the SERC transmission systems meet NERC Reliability Standards.

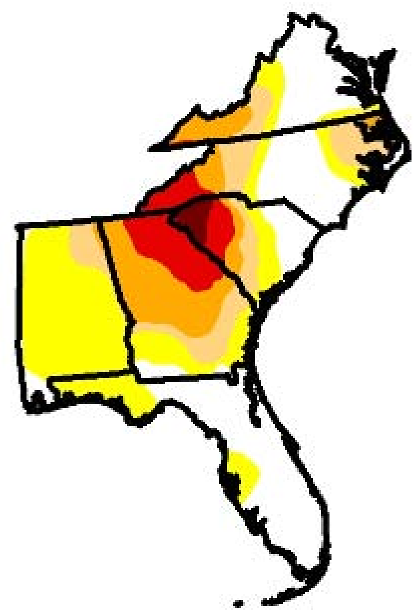
Results from the ERAG (Eastern Interconnection Reliability Assessment Group) sponsored 2008 Summer MRO-RFC-SERC West-SPP inter-regional study indicate potential transmission transfer issues between the Delta sub-region and some neighboring regions involved in the study. The areas of interest from this study indicate that the First Contingency Incremental Transfer Capability (FCITC) from the Delta sub-region to some neighboring interfaces, including SPP and MRO, as “zero”. These transfers are primarily limited by 161 kV transmission facilities on the Entergy-SPP interface for the outage of the ANO-Ft. Smith 500 kV line, which is a tie line between Entergy and Oklahoma Gas and Electric. Previous reliability studies indicate that power flows on these 161 kV transmission lines are extremely sensitive to Entergy and SPP generation dispatch in the local area, as well as transactions modeled across Entergy’s northern interface. While Entergy and other SPP members have committed to upgrading one of these interface constraints (i.e., Danville-Magazine 161 kV line), Entergy is also evaluating other long-term transmission solutions for this limit. However, Entergy does not expect any reliability concerns for the summer of 2008

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.

Operational Issues

Coordinated interregional transmission reliability and transfer capability studies for the shorter term planning horizon were conducted among all the SERC sub-regions and with the neighboring regions. In addition, coordinated intraregional transmission reliability and transfer capability studies for the longer term planning horizon were conducted within SERC. These studies indicate that the bulk transmission systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions.

Drought conditions in SERC are lessoning in some sub-regions; reliability concerns are continuing in other sub-regions in the near-term but long-term outlook is unknown. All sub-regions of SERC experienced drought effects during 2007 which provided a valuable basis for evaluation of future drought conditions. SERC conducted a special assessment including an extreme hydrological scenario more severe in terms of water availability to forecast 2008 summer conditions. Based on the assessment, if the drought continues through 2008, the hydrological conditions leading into 2009 could be more severe. However, at the present time hydrological conditions in 2008 are improving in some areas. While it is difficult to predict on a long-range basis the impact of long-term drought conditions, the members of SERC have now had experience with preparing the special assessment which can be repeated in the future as required. The results of this recent special assessment show that no sub-region identified significant concerns that might threaten reliability for the near-term. At most, some redispatch, modest increases in imports, or operating guidelines will be required. Individual Transmission Planners and Planning Coordinators are continuing drought preparedness initiatives already underway and operational representatives continue as needed to provide opportunities for coordination and sharing of system conditions.



The current status (October 14, 2008) according the US Drought Monitor (brown areas are Drought Level 4 – exceptional)[173] is depicted in the Figure to the right.

All sub-regions of SERC experienced drought effects during 2007 which provided a valuable basis for evaluation of future drought conditions. SERC conducted a special assessment including an extreme hydrological scenario more severe in terms of water availability to forecast 2008 summer conditions. Based on the assessment, if the drought continues through 2008, the hydrological conditions leading into 2009 could be more severe. However, at the present time hydrological conditions in 2008 are improving in many areas. While it is difficult to predict on a long-range basis the impact of long-term drought conditions, the members of SERC have now had experience with preparing the special assessment which can be repeated in the future as required. The results of this recent special assessment show that no sub-region identified significant concerns that might threaten reliability for the near-term. At most, some redispatch, modest increases in imports, or operating guidelines will be required. Individual Transmission Planners and Planning Coordinators are continuing drought preparedness initiatives already underway and operational representatives continue as needed to provide opportunities for coordination and sharing of system conditions.

Reliability Assessment Analysis

Capacity resources in SERC are expected to be able to supply the projected firm summer demand with adequate margin. Although SERC does not specify a regional capacity margin requirement, members adhere to their respective state commission regulations, RTO requirements and/or internal business practices as applicable. The projected long-term capacity margins under various definitions are reflected in Figure 2.

[173] http://drought.unl.edu/dm/monitor.html

Reported potential capacity additions and existing capacity, including uncommitted resources, along with the necessary transmission system upgrades, could satisfy capacity margin needs through 2017. 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 that influence the development of new generating resources. As can be seen in Figure SERC-2, 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 definition NERC specifies for generation status and margin calculation.

In order to address unexpected fuel interruptions due to resource unavailability, SERC entities with large amounts of gas-fired generation connected to their systems have conducted electric-gas interdependency studies. In-depth studies have simulated pipeline outages for near and long-term study periods as well as both summer and winter forecasted peak conditions. Also included, for each of the major pipelines serving the service territory, is 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. 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 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 that 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

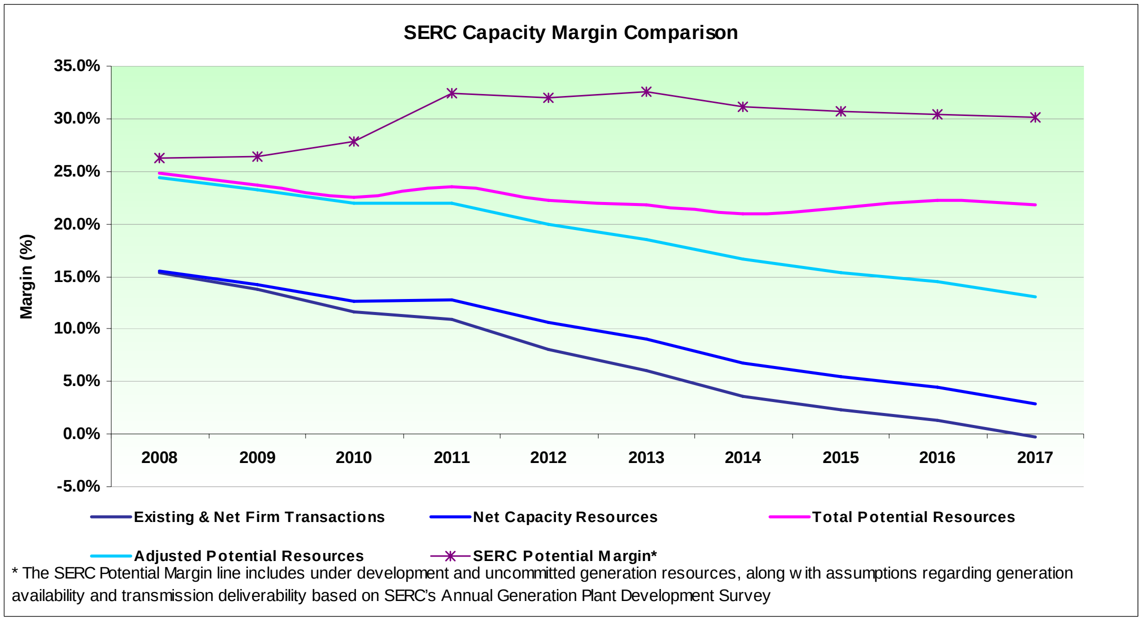


Figure SERC-2: 2008 LTRA SERC Region - Capacity Margin Comparison

Aging Work force Issue

In general, SERC member companies are actively recruiting replacement employees in field and technical functions as the need arises. SERC members recognize the need for continually improving skills as both a business requirement and a potential issue for grid reliability. While SERC members are addressing this issue on an individual company basis, in general, companies work to help enhance the technical education systems through various guidance and support mechanisms, continue development of their technical employees through in-house and outside training, and support employees through continued upgrading of tools. Technical interchanges and industry audits are used to help redefine performance and set challenges that attract capable candidates. Meeting industry standards increasingly requires training and performance requirements that help improve technical capabilities.

Sub-regions

Central

Demand

The 2008 summer net internal demand forecast for the Central Sub-region was 42,163 MW and the forecast for 2017 is 49,673 MW. This year's forecast average annual peak growth rate for 2008-2017 is 1.84% for the sub-region. This is lower than last year's forecast growth rate of 2.1% due to the forecast impacts of new Demand Side Management (DSM) programs and lower economic projections, and is based on normal weather conditions along with monthly energy sales, economic growth, population, employment and gross regional product increases throughout the sub-region. There is a mix of various demand response programs including interruptible demand, new energy efficiency programs, customer curtailing programs, and direct load management including an air conditioner control program. To assess variability, most members within the sub-region use forecasts assuming normal weather, and then develop models for milder and more extreme weather to create optimistic and pessimistic scenarios.

Generation

Members in the Central sub-region reported a range of various categories of capacity for the years 2008-2017. This capacity can be categorized as existing certain and uncertain, planned and proposed and is adequate to meet demand during this time period.

Table SERC-1: Central LTRA Capacity Breakdown		
Capacity Type	**Year 2008**	**Year 2017**
Existing Certain	49,668 MW	47,607 MW
Solar	.56 MW	.56 MW
Biomass	15 MW	15 MW
Hydro	4,965 MW	4,989 MW
Existing Uncertain	4,608 MW	4,759 MW
Proposed capacity	1,183 MW	12,944 MW
Planned capacity	0 MW	2,604 MW
Biomass	2 MW	2 MW

To determine potential resource options for the future, members in this sub-region use long-term contracts and are in the process of either evaluating or adding self-build options to add new capacity.

Purchases and Sales

Members in the Central sub-region reported a range of firm and non-firm sales and purchases for the years 2008-2017. These sales and purchases are external and internal to the region and sub-region and help to ensure resource adequacy within the sub-region. The table below summarizes these transactions during this time period.

Table SERC-2: Central Sub-regional Sales/Purchases		
Transaction Type	**Year 2008**	**Year 2017**
Firm Sales (External: RFC)	66 MW	160 MW
Firm Sales (Internal)	143 MW	244 MW
Non-firm Sales (Internal)	0 MW	167 MW
Firm Purchases (External: RFC)	316 MW	176 MW

Sales of zero for non-firm transactions within the SERC region were reported.

The majority of these sales/purchases are backed by firm contracts for a mix of generation and transmission. Very few are associated with liquidated damages contracts (LDC). Although some members in the Central sub-region participate in Contingency Reserve Sharing Groups for assistance during emergencies, the sub-region is not dependent on outside purchases or transfers to meet its load.

Fuel

Fuel vulnerability is not considered to be a concern. Central sub-region members have a highly diverse mix of suppliers, transportation, supply contracts, on-site storage and fuel alternatives to supply generation. Coal is responsible for 47.8% of member generation in the sub-region. The remaining generation is supported by 13.5% nuclear, 19.1% oil and gas, 3.3% pumped storage, 10.0% hydro and 6.3% net purchases and sales and other/unknown fuel types. Some oil is stored as an alternative fuel. Fuel stocks, transportation systems and supplier communications are considered strong and are monitored routinely for adequacy.

Transmission

For the next ten years, the Central sub-region has planned 9 miles of 230kV, 181 miles of 345kV and 67 miles of 500kV as new bulk transmission lines. The following table shows the transmission additions to the bulk power system that ensure reliability during the next ten years.

The details of the transmission expansion plans and transformer additions are shown in the *Major Transmission Projects > 200 kV* section.

Operational Issues

Sub-regional members plan several generation additions to come into service within the next ten years. These additions will increase reliability by diversification of generation type and also with locations throughout the service territory. Although the sub-region is not predicting any major generation or transmission outages that will affect reliability, generation unit outages will include turbine overhauls. Expected outages will be performed during low peak periods and capacity replacement planned to ensure resource adequacy.

No major environmental/regulatory restrictions or temporary operating measures are expected to affect the reliability of the Central sub-region for the next ten years.

Reliability Assessment Analysis

Net capacity resource margins in the sub-region as reported between the years 2008-2017 are from 15.2% to 0.6% over the ten-year period using NERC's 2008 method as shown in Figure SERC-3. There is no regional, sub-regional, state or provincial marginal requirement for this sub-region. Members within the sub-region project capacity margins based on forecasted demand with the assumptions of normal weather, expected economic conditions, and expected demographics for each specific area.

Resource adequacy analyses are performed on a regular basis, and no significant changes have been reported from last year. Members use planning studies to ensure generation deliverability. Studies are coordinated with neighboring systems to incorporate imports and unit outages. Members report no retirements for the upcoming years. Members within the sub-region rely on quarterly OASIS studies. For example the SERC Near-term Study Group assesses transfer capability issues.

Companies within the sub-region maintain individual criteria to address any problems with stability. UVLS systems have been installed to prevent voltage collapse at Philadelphia, Mississippi, and Knoxville, Tennessee. All other systems are expected to be secure with no anticipated stability issues. Companies within the sub-region do not have a general guideline for on-site, spare generator step-up unit and auto transformers, although TVA has standardized on a small number of 500 kV designs and has studied the interchangeability of existing spares.

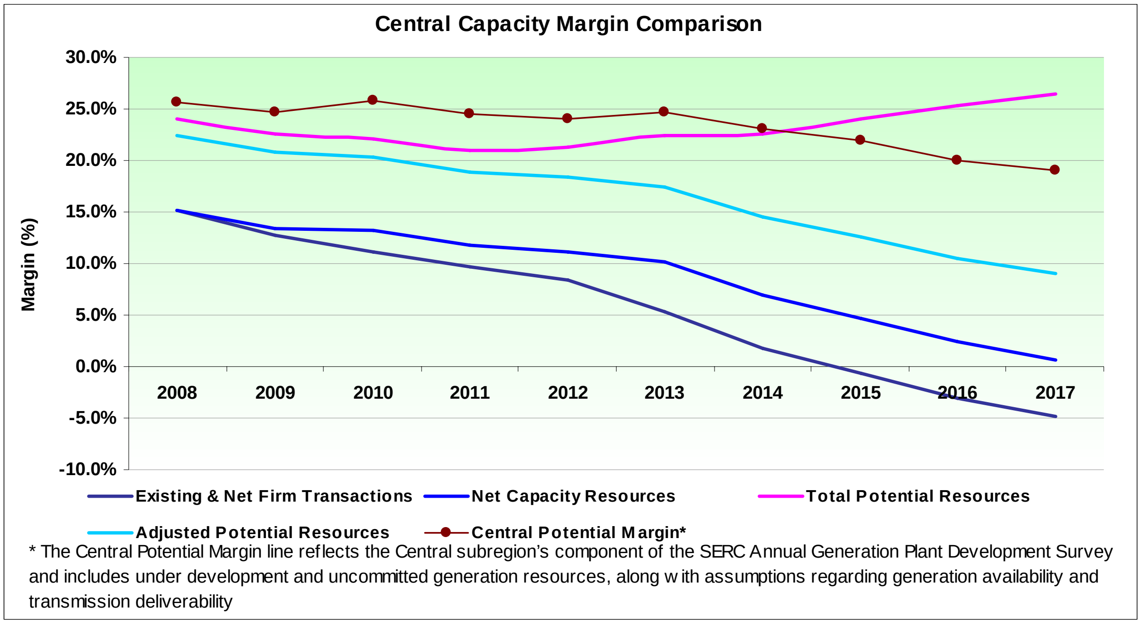


Figure SERC-3: 2008 NERC LTRA SERC Central Sub-region – With Central Potential Margin

In order to address plans for catastrophic events companies use techniques such as black start analysis and training, emergency load curtailment programs, load shedding plans, and purchases of back up power through interconnections. The sub-region experienced a severe drought through 2007 which continued into 2008, and some members have seen a reduction in their power supply from Southeastern Power Administration due to repair work on the Wolf Creek Dam which is likely to continue for several more years. Hydro operations are constantly monitored and evaluated for potential changes and mitigation plans are formed to minimize any threats to reliability. While the continuing drought and dam repairs will affect hydro energy and capacity and cause some thermal de-rating, no problems are foreseen in meeting normal margins and maintaining normal reliability.

To further improve bulk power system reliability, members of the sub-region have reported various programs that will be implemented within the next few years. These programs include: an Operator Training Simulator (in-service in 2009), a Dynamic Thermal Circuit Rating program developed by the Electric Power Research Institute, and improvement to the capabilities of state estimator forward analysis tools.

Member companies have performed assessments to comply with TPL-001 through TPL-004. E.ON develops and files annual Transmission Expansion Plans with the ITO, which identifies and corrects any system deficiencies due to these standards. Members participate in regional studies to assess extreme contingency events. Overall no significant problems have been observed on the bulk electric system from these analyses. Some planned and controlled load shedding may be required for extreme contingencies.

The sub-region has various maintenance and project programs in place that assess the reliability of existing transmission infrastructure and to repair/replace deficient elements as they are encountered. Transmission planning processes routinely identify new facilities and the replacement of existing facilities that reinforces the transmission infrastructure. Inspections, testing, and maintenance are used by members to ensure that reliability is not impacted by infrastructure issues.

To assess short circuit levels on the transmission system within the region, members within the region maintain a short circuit model approximately 3 to 4 years into the future and keep limits well within the limits of currently available circuit breaker technology. None of the members within the sub-region anticipate short circuit levels will impact reliability.

Delta

Demand

The 2008 summer net internal demand forecast for the Delta sub-region was 27,936 MW and the forecast for 2017 is 33,144 MW. This year's compound annual growth rate for 2008-2017 is 1.92% for the sub-region. This is slightly greater than last year's forecast growth rate of 1.9%. A member reported decreases are due to forecasted use per customer in the Residential and Commercial classes during the summer months. Uncertainty and variability is assessed through load scenario development, based on historical temperature probabilities. Peak load scenarios are also performed to assess conditions due to extreme weather found in historical records.

Members within the Delta sub-region reported that they have a mix of demand response programs which consists of interruptible load programs for larger customers and a range of conservation/load management programs for all customer segments.

Generation

Members in the Delta sub-region reported a range of various categories of capacity for the years 2008-2017. This capacity can be categorized as existing certain and uncertain, planned and proposed and is adequate to meet demand during this time period. There are no planned capacity additions and 5,234 MW proposed capacity additions reported within the sub-region.

Table SERC-3: Delta LTRA Capacity Breakdown

Capacity Type	Year 2008	Year 2017
Existing Certain	30,091 MW	29,938 MW
Hydro	79 MW	79 MW
Existing Uncertain	11,993MW	11,993 MW
Planned Capacity	0 MW	0 MW
Proposed Capacity	0 MW	5,234 MW

***No Planned or Proposed Capacity was reported within this sub-region.*

Purchases and Sales

Members in the Delta sub-region reported a range of firm and non-firm sales and purchases for the years 2008-2017. These sales and purchases are external and internal to the region and sub-region and help to ensure resource adequacy within the sub-region. The table below summarizes these transactions during this time period.

Table SERC-4: Delta Sub-regional Sales/Purchases		
Transaction Type	**Year 2008**	**Year 2017**
Firm Sales (External: RFC, SPP)	600 MW	0 MW
Firm Sales (Internal)	1145 MW	888 MW
Firm Purchases (Internal)	1125 MW	92 MW
Firm Purchases (External: SPP)	541 MW	505 MW

Members within the sub-region reported that some of these sales/purchases are backed by firm contracts for a mix of generation and transmission. Very few are associated with liquidated damages contracts (LDC). Even though some members are a member of reserve sharing groups that ensure transmission during emergency conditions, the sub-region is not dependent on outside purchases, transfers, or contracts to meet the demands of its load.

Fuel

Delta sub-regional members reported that they purchase a significant amount of fuel in short-term markets. The entities ensure that they are in constant communication with pipelines, storage facilities and suppliers in the region resulting in continuous up-to-date knowledge of supply and transportation issues. Agreements have been set in place to purchase supply, transportation, balancing, flexibility and peaking services to serve anticipated generation needs.

Fuel supplies and infrastructure are expected to be more than adequate for the upcoming years of demand. Members rely on a portfolio of firm-fuel resources to ensure adequate fuel supplies to generating facilities during projected winter peak demand. Those resources include 17.4% nuclear and 26.7% coal-fired generation that are relatively unaffected by winter weather events, 0.1% fuel oil inventory, 2.5% dual fuel, 0.3% hydro, 2.2% net purchases and sales, and 50.8% natural gas at a company-owned natural gas storage facility, and short-term purchases of firm natural gas. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of potentially problematic issues on system reliability. Other measures include aggressive maintenance of coal delivery infrastructure.

Transmission

For the next ten years, the Delta sub-region has new transmission plans for 226 miles of 230kV and 100 miles of 345kV. These plans consist of additions, retirements and conversions to the bulk transmission lines in this sub-region. The following table shows significant transmission additions to the bulk power system influencing reliability during the next ten years.

The details of the transmission expansion plans and transformer additions are shown in the *Major Transmission Projects > 200 kV* section.

Operational Issues

Sub-regional members expect several generation additions or changes to come into service within the next ten years, but none are expected to be performed during peak season. Approximately 1,100 MW of gas-fired steam generation is assumed to be unavailable for dispatch for the coming year, during which time a life-cycle assessment will be made to determine future disposition of this capacity. There is expected to be no effect on reliability or temporary operating measures required due to these outages. In addition, approximately 500 MW of gas-fired steam generation is also expected to be out of service for a period of 18 months beginning in 2010, during which time it will be converted to a Petroleum Coke/Coal fired facility. The effect of this expected outage on reliability is currently under study.

No major environmental/regulatory restrictions or temporary operating measures are expected to affect the reliability of the Delta sub-region for the next ten years.

Reliability Assessment Analysis

Net capacity resource margins in the sub-region as reported between the years 2008-2017 are from 6.9% to -11.8% as depicted in Figure SERC-4. While these projections indicate a low or negative capacity margin during a portion of the forecast period, it is anticipated that load-serving entities within this sub-region will contract for adequate firm capacity to reliably serve their loads as the near-term horizon approaches. In addition, because of the large amount of non-firm generation available within the sub-region, additional resources could be procured to meet any expected shortfalls in generation capacity. Such non-firm generation was not reported by the sub-region members and thus contributed to the misleading low to negative capacity margins. Non-firm or uncommitted generation within this sub-region totals approximately 5,234 MW. Taking into account these non-firm or uncommitted resources, the capacity margins for 2008 to 2017 would thus change to 6.9% to 5.0%.

While there is no regional or margin requirement for this sub-region, some members within the sub-region project capacity margins based on long and short-term planning, along with Loss-of-Load Studies and reserve allocations from reserve sharing groups. In certain areas of the sub-region, capacity margins are expected to decrease as a result of short-term contacts expiring until 2014. Internal resources are expected to be adequate to meet the needs of the sub-region.

While the sub-region’s generation capacity is predicted to be adequate for supplying its load, it also has access to reserve sharing programs, fuel diversification, fuel policy contracts and other firm resource network contracts and power agreements to ensure supply in times of catastrophic events. Several analyses (Loss-of-Load Expectation, etc.), coordinated with neighboring regions and other SERC sub-regions, assess resource adequacy and transfer capability that will support reliable operations. Unreliable resources are not included in these assessments. No generation deliverability concerns, major transmission additions or significant changes are expected to be an issue for the sub-region for the next ten years. There are no planned retirements of any existing units within the sub-region.

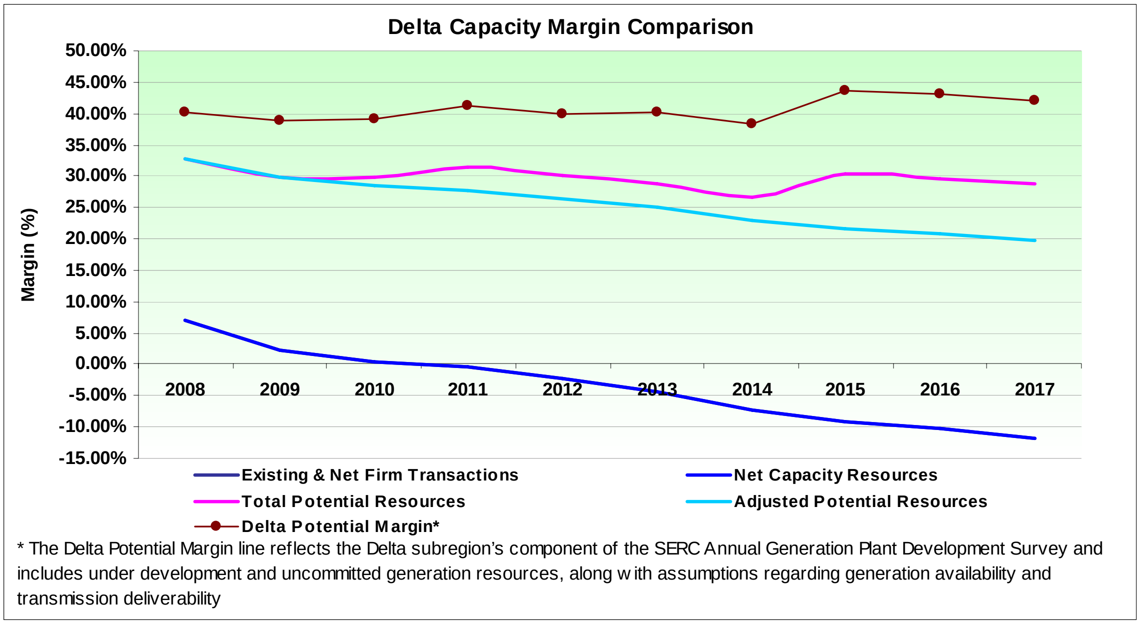


Figure SERC-4: 2008 NERC LTRA SERC Delta Sub-region – With Delta Potential Margin

Studies have been performed 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 sub-region, the 2009 assessment from the study was chosen as a proxy for the near-term evaluation. No critical impacts to the bulk electric power system were identified. While there is no common sub-region wide criteria to address transient dynamics, voltage and small signal stability issues, some members have noted that it adheres to voltage schedules and voltage stability margins. In addition, some members employ static VAR compensation devices to provide reactive power support and voltage stability. Under-voltage load-shedding (UVLS) programs are also used to maintain voltage stability and protect against bulk electric system cascading events. It was reported that the maximum load that can be shed by the UVLS program is approximately 300 MW.

Some members in the sub-region reported that they have Capacity and Energy Emergency Response Plans in place to address catastrophic events. Other members rely on excessive capacity margins or multiple sources for transportation of natural gas in the event of a disruption to a major pipeline to its generators. The sub-region anticipates normal hydro conditions for the upcoming summer based upon current reservoir levels and anticipated rainfall. Studies that assess TPL-001 through TPL-004 standards cover both the near-term and longer-term planning horizons. These studies also cover aspects relating to load flow, short circuit, and system stability. This analysis is used by some members to monitor any issues caused by these extreme events, but does not use these results alone in identifying system improvements. The analysis done in the most recent study revealed no unexpected constraints. Certain members reported that the TPL-004 contingencies that created loading or voltage problems were corrected to meet acceptable planning criteria. The first correction method attempted was a switching solution. If switching was not sufficient, selected loads were shed until all element loadings and voltages were within acceptable planning criteria. To improve the reliability of the bulk power system the sub-region has installed static VAR compensation (SVC) in two locations on the transmission system in order to provide reactive power support and maintain voltage stability. Series compensation on several transmission lines has been installed on the system in order to regulate power flows on the transmission system. Members are continuing to pursue plans to employ these technologies in order to improve and maintain bulk system reliability.

To assess short circuit levels on the 230kV and above transmission system within the region, various members within the sub-region resort to equipment replacement plans that are deemed underrated by short circuit analysis. Other companies will employ techniques such as station reconfigurations where appropriate and effective. To address the concerns of aging infrastructure, members within the sub-region have plans of replacing equipment around the sub-region through maintenance programs. The sub-region does not have guidelines for spare generator units. Companies individually have their own criteria and programs to have spare transformers for reliability.

Gateway

Demand

The 2008 summer net internal demand forecast for the Gateway Sub-region was 19,105 MW and the forecast for 2017 is 20,997 MW. This year's compound annual growth rate for 2008-2017 is 1.05% for the sub-region, which is comparable to last year's forecast growth rate of 1.0%. The forecast peak load for the sub-region is calculated as the sum of the forecast peak loads of the individual members. Members reported that peak growth rates are due to slower economic growth, assumptions on efficiency, and saturation trends used in the Statistically Adjusted End-Use modeling framework. In order to assess the uncertainty and variability in projected demand, some members within the sub-region use regression models, multiple forecast scenario models, and econometric models. Economic assumptions and historical temperature and weather pattern information are considered individually by each sub-region member. The sub-region has a mix of voltage reduction curtailment programs, and other interruptible load programs, but these programs are minor compared to the total demand in the sub-region. The Illinois Commerce Commission is in the process of reviewing a variety of proposed energy efficiency programs, including energy audits and direct load control programs, which could further reduce the rate of growth in the sub-region.

Generation

Members in the Gateway sub-region reported a range of various categories of capacity for the years 2008-2017. This capacity can be categorized as existing certain and uncertain, planned and proposed and is adequate to meet demand during this time period. Some members have reported that specific capacity and resource plans for 2013-2017 have not been identified during this current assessment period. Members plan to enter into bilateral contracts, purchase capacity as needed, or construct new resources as determined by various Integrated Resource Plans. At this time, wind and solar plants are not connected within the sub-region, but over 3,900 MW of wind generation is proposed to connect over the next five years. Biomass plants (landfill gas) supply only a few MWs of capacity to meet the sub-region load requirements and are generally connected to distribution facilities.

Table SERC-5: Gateway LTRA Capacity Breakdown		
Capacity Type	**Year 2008**	**Year 2017**
Existing Certain	24,786 MW	23,916 MW
Hydro	368 MW	368 MW
Existing Uncertain	4,566 MW	4,671 MW
Inoperable	526 MW	86 MW
Planned	0 MW	565 MW

***No proposed capacity was reported within this sub-region.*

Purchases and Sales

Gateway sub-regional members reported a variety of firm and non-firm sales and purchases for the years 2008-2017. These sales and purchases are both external and internal to the region and sub-region. Sales of excess capacity by some members help to ensure resource adequacy within the sub-region. The table below summarizes these transactions during this time period.

Table SERC-6: Gateway Sub-regional Sales/Purchases		
Transaction Type	**Year 2008**	**Year 2017**
Firm Sales (External: RFC)	400 MW	0 MW
Firm Sales (Internal)	420 MW	0 MW
Non-Firm Sales (Internal)	0 MW	176 MW
Firm Purchases (Internal)	28 MW	98 MW
Firm Purchases (External: SPP)	79 MW	79 MW
Non-Firm Purchases	0 MW	234 MW

Most of the members within the sub-region reported that the sales/purchases for 2008 are backed by firm contracts for both generation and transmission. Members reported that liquidated damages contracts (LDC) were not used within the sub-region. Although the subregion has a robust transmission system with numerous interconnections to other regions and neighboring SERC sub-regions, the sub-region is not dependent on outside purchases or transfers to meet the demand and planning reserves.

Fuel

Gateway sub-region members reported various fuel policies and some members have reevaluated fuel inventories and delivery practices as a result of fuel delivery issues. These policies take into account contracts with surrounding facilities, alternative transportation routes, and use of alternative fuels. Some members have developed Integrated Resource Plans to help ensure fuel reliability within the sub-region. These practices help to ensure balance and flexibility to serve anticipated generation needs. The predominant fuel type used in the sub-region is coal, and its share of member's capacity is 56.6% of the total generation. Other fuel types in the sub-region are 15.3% gas, 6.3% nuclear, 26.1% oil/gas, 1.9% hydro, and 9.2% other or net sales and purchases. No fuel supply problems are anticipated during the study period.

Transmission

The transmission system in the Gateway sub-region is robust and highly interconnected with EHV tie-lines to MISO, PJM, SPP, and non-MISO members in MRO in addition to the interconnections with SERC members in the Central and Delta sub-regions. The transmission system allows purchases and sales to maintain reliability within the sub-region as well as to import and export power and energy as economic conditions warrant. In the event of capacity shortfalls within the sub-region, the transmission system provides opportunities to import power from sources outside of the sub-region, if generation would be available.

For the next five years, the Gateway sub-region has plans to build 57 miles of 345 kV transmission lines.

The details of the transmission expansion plans and transformer additions are shown in the *Major Transmission Projects > 200 kV* section. Other transmission capacity upgrades are in various stages of the planning process and may be required to maintain reliability for specific needs.

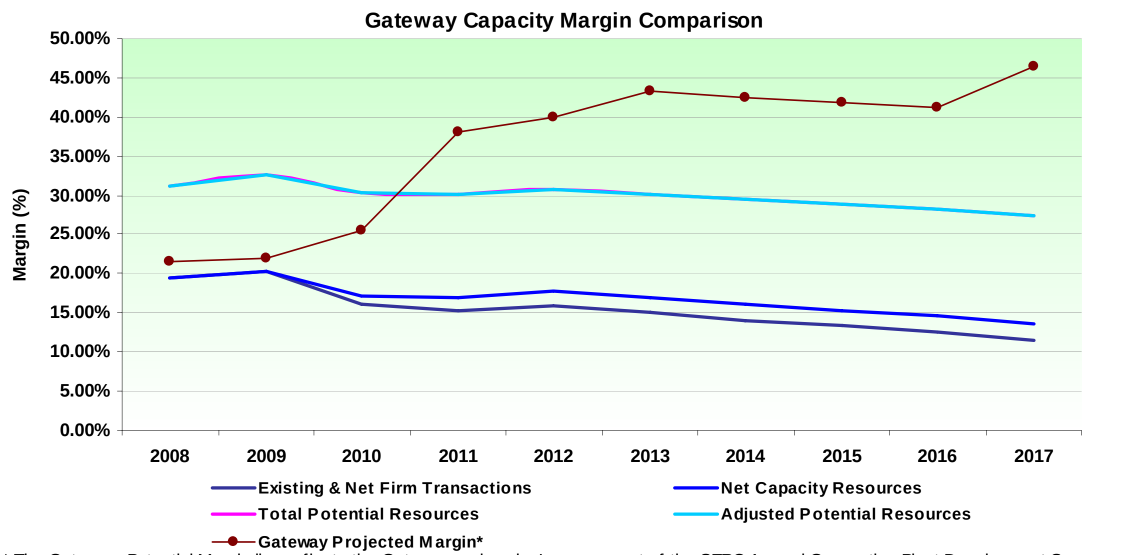
Operational Issues

No reliability problems are anticipated on the transmission systems of the Gateway sub-region for 2008 summer. The City of Springfield-CWLP reported that its Dallman generator unit 1, which experienced an explosion last year that compromised 86 MW, will not be available until the summer of 2009. The new Dallman generator unit 4 is expected to be in service by January 2010. Several members within this sub-region have noted that there are limitations with emissions stipulations, thermal discharge or lake temperature limitations that can have an impact on peak energy needs. Many of these issues would be alleviated with the above normal precipitation received in late 2007 and early 2008. These limitations or any unusual operating conditions are not expected to have a major impact on reliability. The Taum Sauk (440 MW) pumped storage facility in the AmerenUE control area remains unavailable but this is not a reliability concern as adequate resources are available in the sub-region. The Taum Sauk plant is expected to return to service for the summer of 2010.

Reliability Assessment Analysis

Net capacity resource margins in the sub-region as reported between the years 2008-2017 are from 19.4% to 13.6% as shown in Figure SERC-5. There is no single capacity margin requirement for the Gateway sub-region. Members follow established business practices or guidelines from the governing regulatory bodies. Some members within the sub-region project capacity margins for both long and short term planning horizons, and considering new constructed generation, along with Loss-of-Load Studies and reserve allocations from reserve sharing groups. In certain areas of the sub-region, capacity margins are expected to decrease as a result of short-term contacts expiring until 2014. Internal resources, including potential additions, are expected to be adequate to meet the needs of the sub-region even assuming extreme weather scenarios and 90/10 forecast loads. It is estimated that extreme weather could add an additional 5% to the load forecast in the sub-region, resulting in a capacity margin of 15.4% in 2008 and declining to 9.3% in 2017. As mentioned earlier, the sub-region has a mix of voltage reduction curtailment programs, and other interruptible load programs, but these programs are minor compared to the total demand in the sub-region, and should not be needed to maintain reliability considering the amount of generation capacity available in the Gateway sub-region and the reach and strength of the Gateway transmission system to import power from adjacent areas that have capacity available.

Generation additions are proposed throughout the sub-region within the next 5 years. The Prairie State 1,650 MW coal-fired plant in southwestern Illinois is expected to be in service by 2012, and a majority of the new EHV transmission planned in the sub-region is for connection and deliverability of this facility. Other minor increases to coal-fired plants in the sub-region are also planned. Over 3,900 MW (nameplate) of wind generation is proposed to connect to the transmission system in the sub-region through 2013, with approximately 85% of the total located in Illinois. Only a small fraction of this wind generation (no more than 20% of nameplate capacity based on current MISO business practices) would be considered by sub-region members as contributing to the sub-region capacity portfolio during peak conditions. This percentage could change based on experience with the wind plants. In the 10-year period, a 1,650 MW (net) nuclear unit is proposed for central Missouri and its transmission requirements and impacts are under study.



* The Gateway Potential Margin line reflects the Gateway subregion's component of the SERC Annual Generation Plant Development Survey and includes under development and uncommitted generation resources, along with assumptions regarding generation availability and transmission deliverability

Figure SERC-5: 2008 NERC LTRA SERC Gateway Sub-region – With Gateway Potential Margin

Fuel supply in the area is not expected to be a problem. Policies considering fuel diversity, contracts with various suppliers, inventory requirements, and delivery have been put in place throughout the area to ensure that reliability is not impacted. Even though various companies within the sub-region rely on sub-regional studies to assess resource adequacy, the market within this sub-region allows various entities to purchase the energy necessary to meet any shortfalls that would compromise resource adequacy. Members reported that it is not common practice to add uncertain resources in their assessments (LOLE, resource studies, etc). There are no expected major unit retirements that will impact reliability within the next ten years. Retirements of minor generating units total 114 MW over the ten year period 2008-2017.

Deliverability testing studies are performed on an ongoing basis throughout the sub-region to ensure that transmission capacity is sufficient to make the generation deliverable. No concerns for deliverability have been reported within the study years.

A number of major transmission system expansions are expected to be placed in-service over the next 10 years. The addition of the new Mariosa Delta 345/161 kV Substation in the Jefferson City area for 2008 summer has enhanced reliability in central Missouri. The Joachim 345/138 kV Substation addition is planned to enhance reliability to the southern St. Louis County and Jefferson County area of Missouri, and should be placed in-service by the fall of 2008. The addition of a Rush Island-Baldwin 345 kV line in response to the addition of coal-fired generating capacity at the Prairie State facility in southwestern Illinois is expected to be in-service mid-2010. A number of other transmission system expansions are being contemplated, but the timing for such additions awaits a definitive need. All additions are expected to improve reliability within the sub-region. Deliverability problems from generation centers or into local load centers are not anticipated to be an issue.

Sub-regional studies involving power flow, short-circuit, and stability analyses are not performed on a regular basis involving the entire sub-region, but joint studies are performed by the members as needed to address member and sub-regional needs. To address plans for catastrophic events, some members of the sub-region consider diversity of gas supply and rely on generation supplied from various pipelines to safeguard against disruptions from a single pipeline, although the reliance on gas generation in the sub-region is minimal. Other members rely on large interconnections to neighboring systems, energy contracts, diverse generation options and contingency study plans to help safeguard against unforeseen events. The Gateway sub-region has adequate and diverse capacity resources and is heavily interconnected, internally as well as to other SERC sub-regions and NERC regions, to provide system reliability for its members.

Some sub-region members have studied the performance of local area load pockets for multiple contingency events. The addition of capacitor banks, modifications to transmission arrangements, and additional transmission supplies are planned to reinforce these local area supplies. Under Voltage Load Shedding (UVLS) has not been implemented and should not be needed if these planned facility additions are completed in a timely manner.

The sub-region is not experiencing a drought and cooling water reservoirs are expected to be adequate due to heavy precipitation received this spring and early summer. Assessment studies to meet NERC Standards TPL 001 through 004, including both powerflow and stability studies have been performed by the larger members. No major reliability issues have been reported in these studies, which include transient dynamics, voltage, and small signal stability analyses. Members continue to evaluate the performance of their systems studies and upgrade those limiting areas to enhance reliability Members within the sub-region do not anticipate short circuit problems on their transmission systems.

New equipment and techniques such as updating tie line metering, installing new Real Time Data Monitoring System (RTDMS) software, and installing phasor sensing devices are expected to continue within the next ten years as companies attempt to make improvements to improve reliability. Continued use of the phasor measurement equipment installed in various places on the transmission and interconnection system are expected to provide options to operations personnel in assessing immediate near-term conditions as well as provide data for disturbances experienced on the system.

Sub-region members are also individually implementing programs to address aging infrastructure and spare equipment through coordinated transmission planning activities, and other programs. Some Gateway members have a limited number of spare transmission transformers and GSU transformers to minimize the outage time to portions of the transmission system and major power plant units. There are no anticipated reliability problems associated with these facility issues.

Southeastern

Demand

The 2008 summer net internal demand forecast for the Southeastern Sub-region is 48,215 MW and the forecast for 2017 is 60,156 MW. This year's compound annual growth rate for 2008-2017 is 2.49% for the sub-region. This is comparable to last year's forecast growth rate of 2.4%. Demand forecast is based on normal weather conditions and uses normal/median weather, normal load growth and conservative economic scenarios. The sub-region 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 effects of summer peaks. To assess variability, some sub-region members develop forecasts using econometric analysis based on approximately 30 year (normal, extreme and mild) weather, economics and demographics. Others within the sub-region use the analysis of historical peaks, reserve margins and demand models to predict variance.

Generation

Members in the Southeastern sub-region reported a range of various categories of capacity for the years 2008-2017. This capacity can be categorized as existing certain and uncertain, planned and proposed and is adequate to meet demand during this time period. The resources for reliability are evaluated by future power supply plans, purchased power through contracts, and self building options of generation.

Table SERC-7: Southeastern LTRA Capacity Breakdown

Capacity Type	Year 2008	Year 2017
Existing Certain	59,540 MW	62,611 MW
> Existing Certain Hydro	4,058 MW	4,058 MW
Existing Uncertain	5,800 MW	5,800 MW
Planned	0 MW	1,682 MW
Proposed	0 MW	9,253 MW

***No proposed capacity was reported within this sub-region.*

Purchases and Sales

Southeastern sub-regional members reported a range of firm sales and purchases for the years 2008-2017. These sales and purchases are external and internal to the region and sub-region and help to ensure resource adequacy within the sub-region. The table below summarizes these transactions during this time period.

Table SERC-8: Southeastern Sub-regional Sales/Purchases		
Transaction Type	**Year 2008**	**Year 2017**
Firm Sales (External: FRCC)	1,551 MW	0 MW
Firm Sales (Internal)	931 MW	1,038 MW
Firm Purchases (Internal)	408 MW	332 MW

Members within the sub-region reported that some of these sales/purchases are backed by firm contracts for a mix of generation and transmission. None of these transactions are considered liquidated damages contracts (LDC). To ensure transmission during emergency conditions, the sub-region is not dependent on outside purchases or transfers to meet the demand and planning reserves.

Fuel

Southeastern sub-regional members reported that fuel vulnerability is not an expected reliability concern for the study period. The members have a highly diverse fuel mix to supply its demand, including nuclear, PRB coal, Eastern coal, natural gas and hydro, along with dual fuel units. Some members have implemented fuel storage and coal conservation programs, and various fuel policies to address this concern. These tactics help to ensure balance and flexibility to serve anticipated generation needs. Coal fired generation comprises 41.7% of the total generation reported by sub-regional members. Other fuel types within the sub-region are 9.8% nuclear, 29.9% oil/gas, 2.6% pumped storage, 6.8% hydro and 9.2% net sales and purchases. No fuel supply problems are anticipated during the study period.

Transmission

For the next ten years, the Southeastern sub-region members have transmission plans or projections for 712 miles of 230 kV and 195 miles of 500kV. These plans consist of additions, retirements and conversions to the bulk transmission lines in this sub-region. The following table shows significant transmission additions to the bulk power system influencing reliability during the next ten years.

The details of the transmission expansion plans and transformer additions are shown in the *Major Transmission Projects > 200 kV* section.

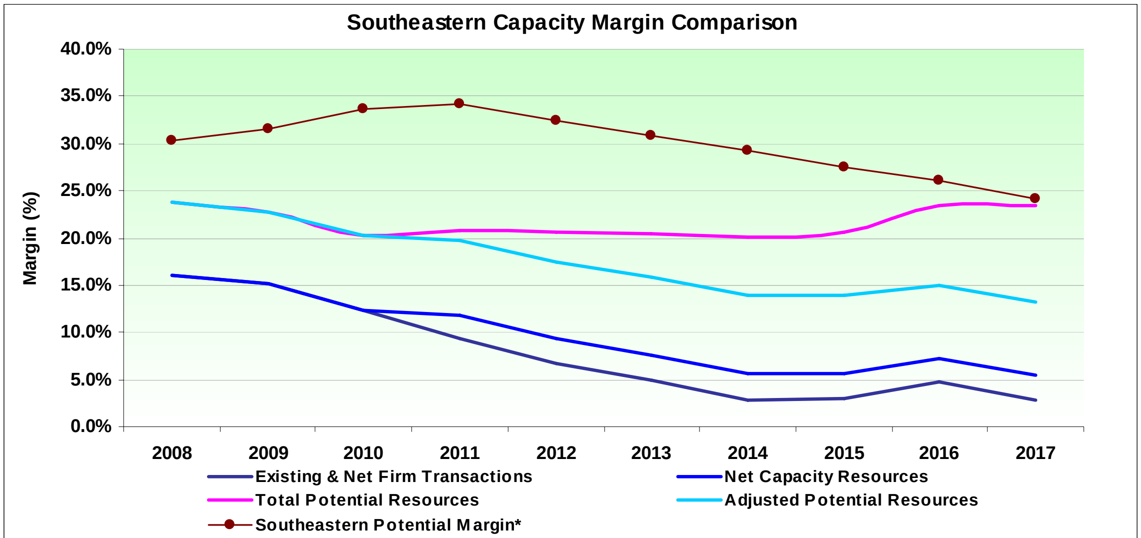
Operational Issues

No reliability, environmental or regulatory restrictions are anticipated on the transmission systems of the Southeastern sub-region. Members have reported that some hydro and other generation units will undergo major rehabilitation, but outages will be coordinated in such a way that system reliability and contractual commitments will not be affected.

Reliability Assessment Analysis

Net capacity resource margins in the sub-region as reported between the years 2008-2017 are from 16.1% to 5.4% as shown in Figure SERC-6. There are no regional, or sub-regional, marginal requirements for this sub-region. Some members within the sub-region project capacity margins based on existing resources, unit retirements, expected firm purchases agreements and anticipated generation additions. Internal resources are expected to be adequate to meet the needs of the sub-region. Unit retirements within the sub-region total 1,006 and the majority (925 MWs) are scheduled to retire in the 2011-2013 period.

Capacity in the sub-region should be adequate to supply forecast demand. There are no significant changes to LOLP, EUE, generation resource models and other resources adequacy studies that will affect margins. Various tactics are being used to ensure these resource adequacy measurements are within an acceptable range. Annual Transmission Transfer Capability, System Impact, and Facility studies are performed jointly with various members within the sub-region to determine external generation deliverability. Operating guides are developed as necessary to ensure acceptable transfer levels are reached. Some entities perform annual contingency analysis (studies typically covering up to ten future years) and biannual stability studies to ensure internal generation deliverability. Current studies have identified no deliverability concerns or major unit retirements expected to impact reliability. No significant changes are expected to come about in the next ten years.



* The Southeastern Potential Margin line reflects the Southeastern subregion's component of the SERC Annual Generation Plant Development Survey and includes under development and uncommitted generation resources, along with assumptions regarding generation availability and transmission deliverability

Figure SERC-6: 2008 NERC LTRA SERC Southeastern Sub-region – With Southeastern Potential Margin

Various companies within the sub-region have firm transportation, gas storage, firm pipeline capacity, and on-site fuel oil and coal supplies to meet the peak demand. The sub-region has a very diverse fuel portfolio and implements fuel storage, sourcing, dual fuel capability units, and conservation programs. Using 90/10 forecast, some members show that planning reserves are adequate to meet weather and forecast uncertainty. Other members anticipate utilizing existing resources, energy purchases, and/or interruptible load shedding to maintain reliable operation of their transmission system in these more severe conditions. Variable resources are not included in these studies.

Studies to determine transmission needs for new resources in the next ten years are currently being performed by various members in the sub-region. Bulk transmission projects will be put into place with long lead times in order to accommodate any needed resources. Rapid forecasted load growth in the Metro Atlanta area will drive several 230 kV and 500 kV projects over the next ten year planning period. The Southeastern sub-region does not have sub-regional criteria for dynamics, voltage or small signal stability; however, various companies within the sub-region maintain individual criteria and perform appropriate studies to address any stability issues. All systems are expected to be secure for the study period.

Members are expected to address catastrophic events by contractual arrangements that amount to reserve sharing agreements, fuel supply diversity, interruptible load contracts, and excess reserves. Other members perform transmission studies considering loss-of-pipeline, extreme event (TPL-003 & 004), and infrastructure security studies. Studies are also conducted considering outages of up to three 500 kV lines within neighboring utilities. The purpose of all these is to assess vulnerability to catastrophic events and the development of appropriate mitigation plans. The general conclusion is that the system is capable of weathering many potential catastrophic events with minimal impacts on neighboring systems.

Various areas are currently experiencing drought conditions; however recent weather assessments show significant improvement and this trend is expected to continue throughout 2008. The sub-region members participated in the SERC regional drought assessment which did not identify significant reliability impacts from the drought. Although hydro generation is predicted to be lower than normal for the upcoming season, reliability will not be affected due to ready access to other generation sources. Members' planning studies within this sub-region cover TPL-001 through TPL-004 to ensure adequate and compliant systems. No problems were cited for the next ten years and members stated that mitigation plans for previous problems are currently being addressed.

Tools such as the installation of microprocessor based relays in transmission facilities, Dissolved Gas Analysis monitoring capabilities on Generator Step-Up transformers (GSUs), power flow analysis programs, and Static VAR Compensators have helped members take steps to improve the reliability and robustness of the system. Short circuit limits are assessed through fault current studies and exceeded limits are mitigated through breaker replacements, transient recovery voltage capacitors, and the installation of reactors. Aging infrastructure is addressed by equipment testing, maintenance programs and equipment replacements when it nears the end of its useful life. Members do not anticipate that planning or operational activities will be influenced by an aging infrastructure. Guidelines for on-site spare GSUs are implemented on an individual member basis within the sub-region. A variety of techniques such as maintaining a spare unit for all GSUs, programs for sharing spare transformers, and equipment loss programs are practiced by the sub-region to maintain equipment reliability.

VACAR

Demand

The 2008 summer net internal demand forecast for the VACAR Sub-region is 61,103 MW and the forecast for 2017 is 72,100 MW. This year's compound annual growth rate for 2008-2017 is 1.86% for the sub-region. This is comparable to last year's forecast growth rate of 1.8%.

Members reported that peak growth rates are lower due to a slight economic decline and DSM reductions, but overall rates are comparable to last year's rates. Demand forecast is based on averages of the latest 20 to 35 years of historical weather, forecast economic growth, and regressing demographics against system load. These tools are used to develop weather variables for forecasting peak demands. Some members reported that the demand forecast is based on a 50-50 weather projection. The sub-region has a mix of various demand response programs including interruptible demand, customer curtailing programs, Standby Generator Control, Residential Time-of-Use, General Service and Industrial Time-of-Use, and Hourly Pricing for Incremental Load Interruptible programs to reduce the affects of summer peaks. To assess variability, some members within the sub-region use forecasts that are developed using assumptions through economic models, historical weather conditions, energy consumption and demographics. Others assess variability of forecast demand by accounting for reserve margins instead.

Generation

Members in the VACAR sub-region reported a range of various categories of capacity for the years 2008-2017. This capacity can be categorized as existing certain and uncertain, planned and proposed and is adequate to meet demand during this time period. The resources for reliability are evaluated by future power supply plans, forward purchased power agreements with conventional and renewable resources, conservation programs, and self building options of generation.

Table SERC-9: VACAR LTRA Capacity Breakdown

Capacity Type	Year 2008	Year 2017
Existing Certain	72,934 MW	71,007 MW
Hydro	3,721 MW	3,730 MW
Biomass	225 MW	225 MW
Existing Uncertain	2,005 MW	2,005 MW
Inoperable	65 MW	65 MW
Planned	349 MW	3,009 MW
Proposed	0 MW	3,298 MW

Purchases and Sales

VACAR sub-regional members reported a range of firm sales and purchases for the years 2008-2017. These sales and purchases are external and internal to the region and sub-region and help to ensure resource adequacy within the sub-region. The table below summarizes these transactions during this time period.

Table SERC-10: VACAR Sub-regional Sales/Purchases

Transaction Type	Year 2008	Year 2017
Firm Sales (External: RFC)	50 MW	0 MW
Firm Sales (Internal)	200 MW	100 MW
Firm Purchases (Internal)	1,538 MW	1,052 MW
Provisional Purchases (Internal)	0 MW	753 MW

Members within the sub-region reported that some of these sales/purchases are backed by firm contracts for a mix of generation and transmission. Very few transactions are considered liquidated damages contracts (LDC). To ensure transmission during emergency conditions, the sub-region is not dependent on outside purchases or transfers to meet the demand and planning reserves.

Fuel

Fuel vulnerability is not a concern within this sub-region. The members have a highly diverse mix of options which consist of on-site storage, transportation alternatives and fuel contracts to ensure supply to its resources. Other mitigation plans generally involve tiered strategies that are invoked depending on the severity of the situation. This guidance on managing fuel in short supply has been formalized in procedures as required by NERC Reliability Standards. These tactics help to ensure balance and flexibility to serve anticipated generation needs for the upcoming season. The sub-region has 26.1% of coal fired generation, 31.5% dual fuel (gas/oil), 2.7% oil, 2.0% gas, 8.1% pumped storage, 5.1% hydro, and 2.7% other and net sales and purchases. No fuel supply problems are anticipated during the study period.

Transmission

For the next ten years, the VACAR sub-region has new transmission plans for 697 miles of 230 kV and 185 miles of 500kV. These plans consist of additions, retirements and conversions to the bulk transmission lines in this sub-region. The following table shows significant transmission additions to the bulk power system influencing reliability during the next ten years.

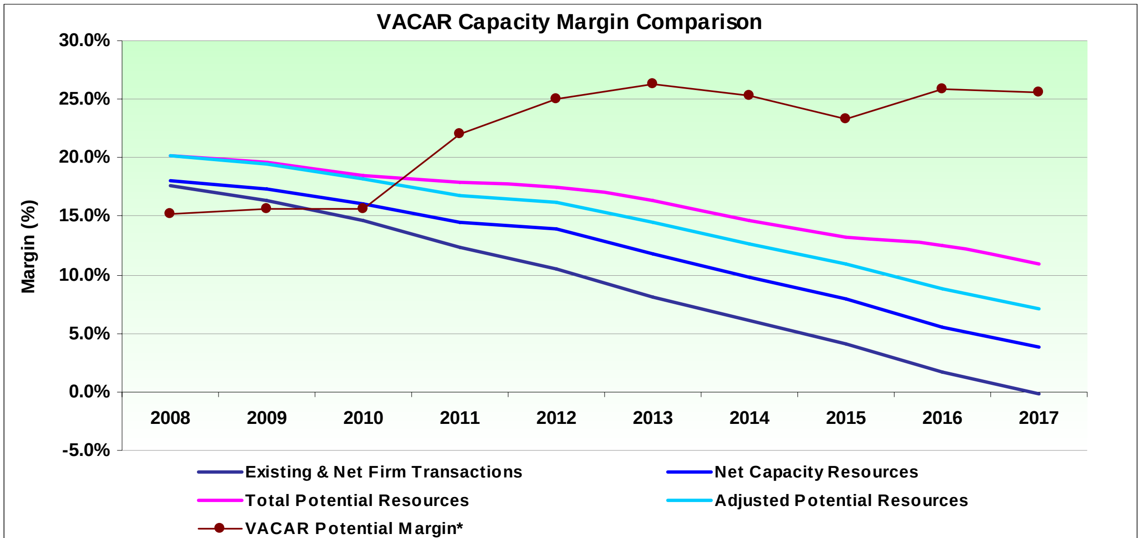
The details of the transmission expansion plans and transformer additions are shown in the *Major Transmission Projects > 200 kV* section.

Operational Issues

For the next ten years members within the VACAR sub-region intends to perform capital improvements, routine and major maintenance activities, but are anticipated to be scheduled during lower demand periods (spring and fall). These outages are not expected to affect its system reliability during this time period. The sub-region also plans to add approximately 834 MW from 2012 through 2018 in the form of contracts and/or generation. Some of these additions are to replace expiring contracts. They too are not expected to cause a major deviation from the current reliability levels as a result of these additions. Some members also expected to slightly reduce generation due to the installation of scrubbers to fossil units due to North Carolina Clean Smokestacks legislation. Operating licenses are expected to have some restrictions if the drought in the area continues to limit peaking capacity for long durations. Although all of these environmental factors are issues within the sub-region, members are not predicting that these issues will have major impacts on reliability.

Reliability Assessment Analysis

Net capacity resource margins in the sub-region as reported between the years 2008-2017 are from 18.1% to 3.8% as shown in Figure SERC-7. There is no regional, sub-regional, state or provincial marginal requirement for this sub-region. Some members within the sub-region project capacity margins based on long-term planning tools which considers a combination of weather-induced load, the probability of units on outage, maintenance scheduling, and operating reserve obligations, resource adequacy studies and system reserve margins. Others rely on loss of load expectation studies to continue to guide the level of reserves maintained to ensure reliable service. To assess resource adequacy, some members have conducted studies and have determined that LOLP, LOLE and EUE figures are comparable to those for the previous year's study. These studies may include estimates of the impacts of forced and planned outages on the system operation. Other members use reserve margins to account for worse-case scenarios with unavailability. However, members have reported that there are no significant changes from last year's assessment that will impact reliability.



* The VACAR Potential Margin line reflects the VACAR subregion's component of the SERC Annual Generation Plant Development Survey and includes under development and uncommitted generation resources, along with assumptions regarding generation availability and transmission deliverability

Figure SERC-7: 2008 NERC LTRA SERC VACAR Sub-region – With VACAR Potential Margin

The retirement of approximately 1,000 MW of older coal-fired capacity by the end of 2018, along with the retirement of 500 MW of older combustion turbines by 2015 are expected to affect the sub-regions resources over the next ten years. Companies are prepared to mitigate this issue by implementing Integrated Resource Plans to determine new resource requirements over the next ten years. To ensure generation deliverability, some members use deliverability load test as a requirement for new generation that will serve load in their system. These tests ensure that all new generation is accessible for the supply of load. Other members within the sub-region rely on contracts for fuel and transportation, operating limits and security constraints to ensure their deliverability. Fuel supplies are expected to be adequate. Members have a very diverse mix of suppliers, transportation contracts, fuel switching plants and on-site storage to ensure adequacy of fuel supply. No fuel supply or delivery issues are expected for this study period. Adequate reserve capacity is maintained in various ways to address resource availability issues (contracts, existing resources, etc.). In addition, members participate in a VACAR reserve sharing agreement whereby VACAR members supply emergency power to other members upon request. Other companies are evaluating the economics and impacts of potentially adding large baseload generation facilities by 2018 or later. To ensure resource adequacy against operational issues due to unexpected conditions, members implement emergency procedures such as Primary Reserve Warnings, Maximum Emergency Generation, Emergency Load Response programs, excess reserve programs, DSM, interruption of firm load, load forecasting tools, and reserve sharing groups. The members within this sub-region are divided in how they count renewable resources within their studies. Some members include them in their models as a design capacity value and others prefer to not include them in capacity counted on for resource adequacy. VACAR members report no major transmission additions or specific deliverability problems from generation centers that could impact reliability.

Members within the VACAR sub-region are involved in studies performed by SERC Study Groups and interregional reliability assessments conducted under the direction of the ERAG Management Committee. These studies analyze transfer capability problems and constraints throughout the sub-region. No constraints to the bulk electric system for the study period was identified that could impact reliability. The VACAR sub-region does not have a sub-regional criterion for dynamics, voltage and small signal stability. Various companies within the sub-region perform individual studies in accordance with NERC Reliability Standards and maintain individual criterion to address any problems with these stability issues. The sub-region does not predict any stability issues that will impact reliability.

To mitigate catastrophic events, VACAR members use various options such as firm purchased power sources, excess reserve margins, membership in reserve sharing agreements, as well as fuel source diversity. Companies have also formed Emergency Action Plans for Power System Disasters to provide a systematic and effective means of restoring power systems within the sub-region. Members report that they have experienced a drought and are expecting conditions to continue for the upcoming summer 2008 season. These conditions have caused substantial constraints on hydro operations. However, coupled with other resources, projected hydro generation and reservoir levels are expected to be adequate to meet both normal and emergency energy demands for the 2008 summer. Members within the sub-region are also monitoring drought conditions through studies to assess the expected severity and its impact on the system.

TPL-001 through TPL-004 are commonly studied throughout the sub-region. Companies implement these studies internally and coordinate externally with neighboring companies. Members report very little problems from the results of the studies. Problems that were reported showed that companies needed to address line loadings (mitigated through operating guides) and line outages that will restrict units. Operating procedures are being put in place to address these issues so that reliability will not be impacted during the upcoming years. Improved SCADA systems with real-time analysis tools, small signal stability analysis tools, transient stability programs, static VAR compensators are all tools that are being evaluated and purchased within the sub-region to improve reliability. Members are individually evaluating plans to assess and limit short circuit levels. Various companies evaluate equipment design limits and use a variety of solution options such as equipment replacements, system reconfigurations, and the installations of reactors to manage problematic locations. Programs are also implemented around the sub-region to address aging infrastructure. Programs such as maintenance programs, transmission projects, asset management programs, and redundancy programs all help companies to assess their systems for improvement. The sub-region also has individual guidelines for spare GSUs and autotransformers. Members use various practices such as membership in spare equipment programs and replacement programs to address the issue.

Region Description

The SERC Region is a summer peaking region covering all or portions of 16 central and southeastern states. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles. The SERC Reliability Corporation (SERC) is the regional entity for the region and is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply system. SERC membership includes 63 member entities consisting of publicly owned (federal, municipal and cooperative), investor owned operations. In the SERC Region there are 31 balancing authorities and over 200 registered entities under the NERC functional model.

SERC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. SERC is divided geographically into five sub-regions that are identified as Central, Delta, Gateway, Southeastern, and VACAR. Additional information can be found on the SERC Web site (www.serc1.org)

SPP Highlights

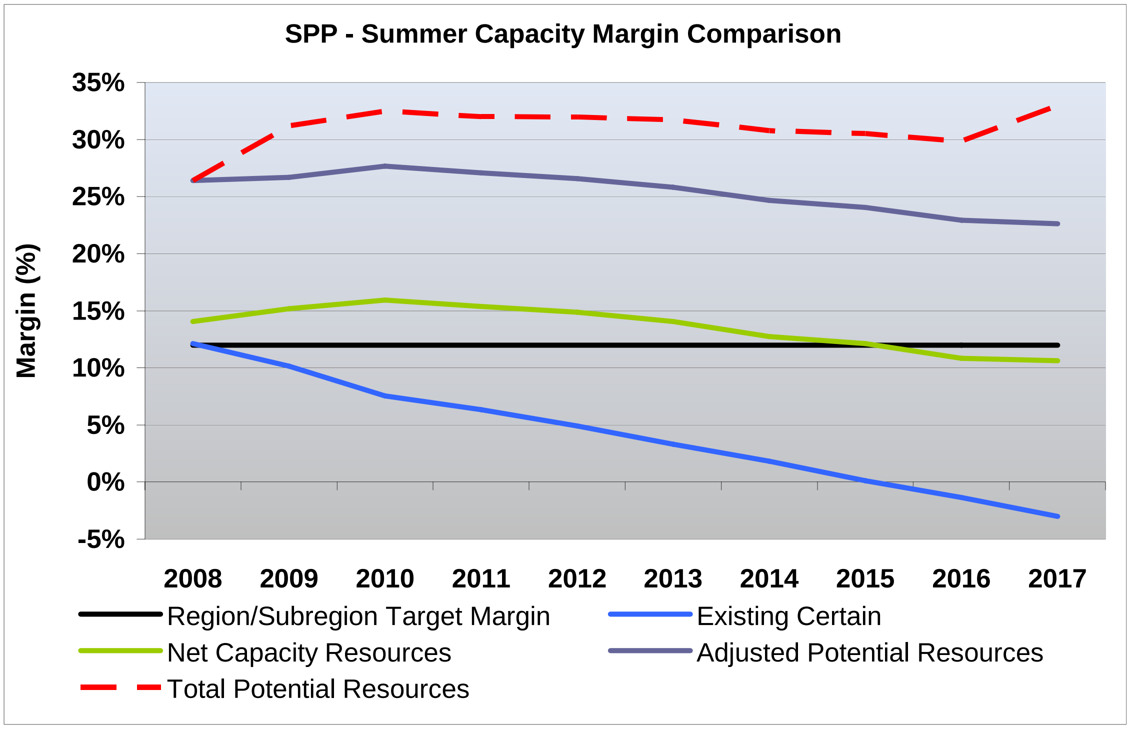
The annual net capacity margin for SPP is greater than the required 12 percent until the year 2014, where the margin drops to 11.5 percent. The resources internal and external to the SPP region that are needed to meet the required 12% capacity margin based on the 2013 forecast total 53,860 MW and 2,789 MW respectively. For the remaining years (2014 through 2017), SPP anticipates more resources will be qualified as certain and can be counted against capacity margin in the next few years.

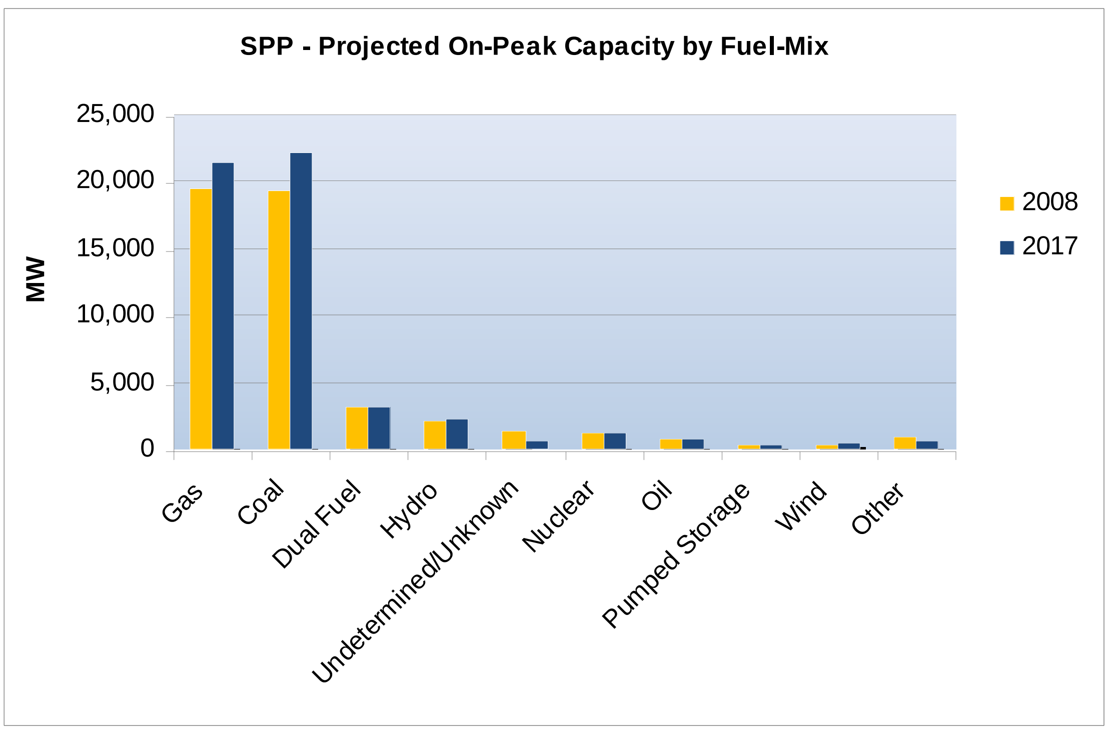
These capacity margin projections include the effects of demand–side response programs, such as direct–control load management and interruptible demand. Currently SPP does not have specific demand response program. However, according to SPP's Strategic Plan, SPP has established a Center of Excellence (COE) to leverage collective knowledge and provide member areas including conservation and efficiency (IRP, DSM). In the meantime, over the next ten years, interruptible demand relief is expected to increase from 487 MW to 529 MW. Also, SPP anticipates that programs initiated by its state regulators, members and other parties coupled with an expansion of energy markets will bring Demand Resources to an increasing point of greater significance.

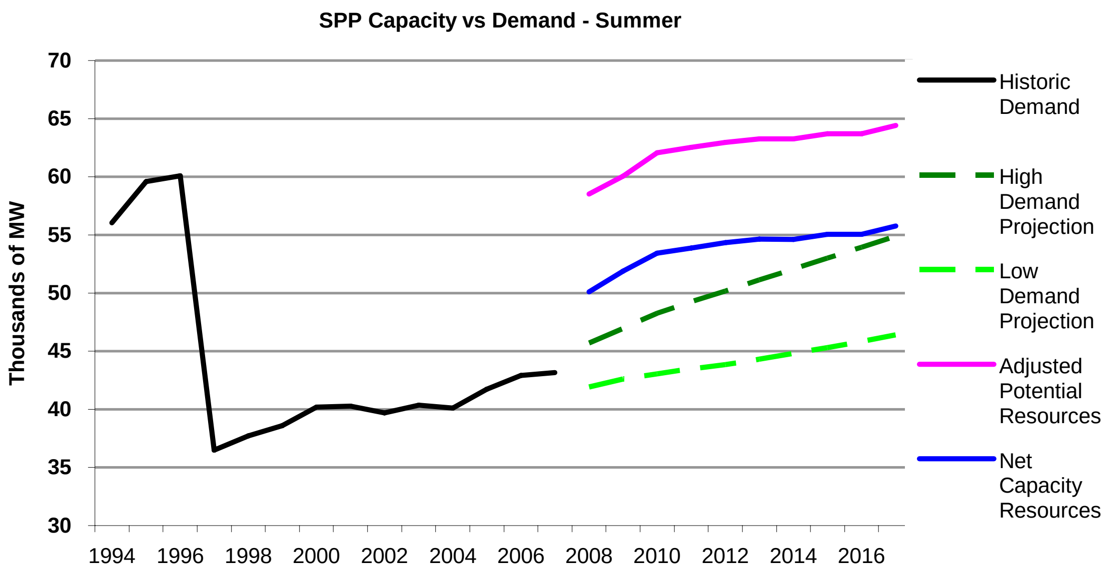
The SPP Transmission Expansion Plan 2008-2017 reported approximately $2.2 billion of transmission network upgrades for the years 2008 through 2017. Network upgrades identified in the near term four year horizon, approximately $762 Million, were approved by the SPP Board of Directors (BOD) with issued Notifications to Construct. They are specifically needed for reliability and these network upgrades have a financial commitment lead time falling inside the 2008 through 2011 four year commitment window.
In addition to the STEP plan, SPP has also conducted a EHV Overlay study. The objective of this study is to develop a long range strategic assessment of the reliability, capacity and seams integration needs of the grid through the use of 345kV, 500kV and 765kV or higher transmission improvements. The study considered four design options to meet these objectives ranging from $6.9 Billion to $7.1 Billion. All these options evaluated the combination of 765 and/or 500-345 kV option.

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

The penetration of wind generation in the western half of SPP footprint could have a significant impact on operations due to the variable nature of this type of resource. SPP is in process of scoping wind integration and penetration study that will help address market/operations and planning needs associated with additional wind development in the region.


SPP - Summer Capacity Margin Comparison
Margin (%)
35%
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


SPP - Projected On-Peak Capacity by Fuel-Mix
MW
25,000
20,000
15,000
10,000
5,000
0
Gas
Coal
Dual Fuel
Hydro
Undetermined/Unknown
Nuclear
Oil
Pumped Storage
Wind
Other
2008
2017


SPP Capacity vs Demand - Summer
Thousands of MW
70
65
60
55
50
45
40
35
30
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources

SPP Self Assessment

Southwest Power Pool (SPP) continues to anticipate consistent growth in demand and energy consumption over the next ten years. Significant generation capacity using uncommitted resources is forecasted in SPP to be available throughout the planning horizon to meet native network load needs with committed generation resources meeting minimum capacity margins until 2014.

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 1.7 percent, from 43,167 MW in 2008 to 50,640 MW in 2017. This is consistent to the 2007 LTRA ten–year (2007–2016) forecasted growth rate of 1.7 percent.

For the 2008–2017 timeframe, the projected annual rate of growth for energy consumption in the SPP region is 1.5 percent, from 208,532 GWh in 2008 to 246,409 GWh in 2017. This is slightly less as compared to the previously forecasted growth rate of 1.8 percent.

Each SPP member annually provides a ten–year forecast of peak demand and net energy requirements. The forecasts are developed in accordance with generally recognized methods 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 along with the annual forecast to SPP.
- Economic, technological, sociological, demographic, and any other significant factors are considered when producing the forecast.

The resultant SPP forecast is the total of the member forecasts. High and low growth rates and unusual weather scenario bands are then produced for the SPP regional demand and energy forecasts. As such, SPP criteria require that members maintain a 12 percent capacity margin, unless their system is primarily hydro–based where the required margin is lowered to 9 percent. This requirement ensures to cover any variation in the load forecast along with maintaining resource adequacy within the SPP footprint.

Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands used for assessing net capacity margins are based on normal weather conditions and do not include interruptible loads.

These capacity margin projections include the effects of demand–side response programs, such as direct–control load management and interruptible demand. Currently SPP does not have specific demand response program. However, according to SPP's Strategic Plan[174], SPP has established a Center of Excellence (COE) to leverage collective knowledge and provide member areas including conservation and efficiency (IRP, DSM). In the meantime, over the next ten years, interruptible demand relief is expected to increase from 487 MW to 529 MW. Also, SPP anticipates that programs initiated by its state regulators, members and other parties coupled with an expansion of energy markets will bring Demand Resources to an increasing point of greater significance.

To quantify peak demand uncertainty and variability due to extreme weather, economic conditions, and other variables an analysis of our region has been completed by the Bandwidth Working Group. The outcome of this report[175] 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.

Generation

For the 2008-2017 assessment period, SPP projects it will have 47,151 MW towards Existing Certain Capacity; 9,892 MW Existing Uncertain Capacity; 5,849 MW Planned Capacity and 2,758 MW of Proposed Capacity resources that are either in-service or are expected to be in-service. The Existing Certain Capacity amount portions that are from variable plants are 194 MW (Wind), 3,045 MW (Hydro), and 365 MW (Biomass). Existing Uncertain Capacity amount portions that are from variable plants (mostly wind) is 976 MW. Planned Capacity for 2017 that are from variable plants (mostly wind) is 150 MW. At present, SPP relies on their members to submit the generation output (including variable) towards certain capacity based on the historical and the actual test data. This data gets routinely scrutinized by SPP staff for accuracy and an internal supply adequacy audit is conducted every five years to verify and document all the historical as well as test data for all the resources.

Purchases and Sales

A small portion of SPP's capacity margin comes from the purchases from other regions. The transactions for the 2008-2017 assessment period are 2,149 MW (this is a ten year average) that is purchased from other regions. Based on a ten year average (2008-2017), 1960 MW of these purchases are firm, and 189 MW is firm delivery service from WECC administered under Xcel Energy's OATT. None of the purchase contracts are Liquidated Damage Contracts.

SPP has a total of 1,550 MW of firm sales to regions external to SPP. None of the sales contracts are Liquidated Damage Contracts.

SPP members along with neighboring entities like Entergy from the SERC region have formed a Reserve Sharing Group. The members of this group receive contingency reserve assistance from other SPP Reserve Sharing Group members. The SPP's Operating Reliability Working Group will set the Minimum Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on-line.

[174] http://www.spp.org/section.asp?pageID=83

[175] The Demand and Energy Bandwidth Report is located here (http://www.spp.org/publications/BWG_Report_2003.pdf).

Fuel

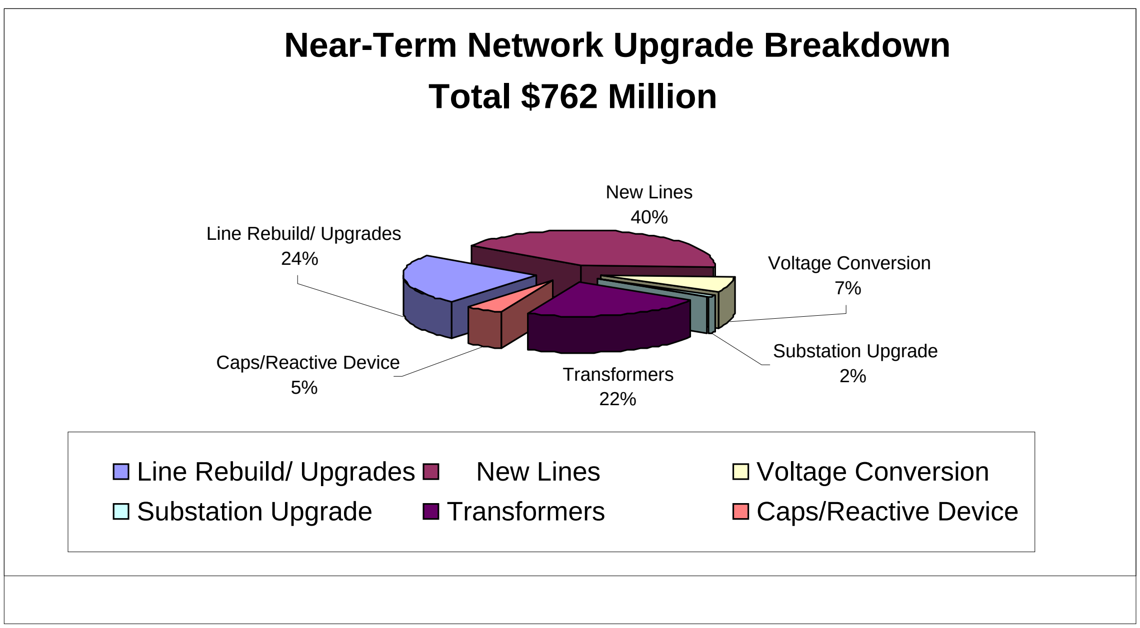
SPP monitors potential fuel supply limitations by consulting with its generation owning and controlling members at the beginning of each year. Presently, there are no known infrastructure issues which could affect fuel deliverability as SPP is blanketed by major pipelines and railroads to provide an adequate fuel supply. In addition, coal and natural gas power plants, which make up approximately 48% and 44% of total generation respectively, are required by SPP criteria to keep sufficient quantities of standby fuel in the 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.

Transmission

The SPP Transmission Expansion Plan 2008-2017[176] reported approximately $2.2 billion of transmission network upgrades for the years 2008 through 2017. Network upgrades identified in the near term four year horizon, approximately $762 Million, were approved by the SPP Board of Directors (BOD) with issued Notifications to Construct. They are specifically needed for reliability and these network upgrades have a financial commitment lead time falling inside the 2008 through 2011 four year commitment window.

SPP is committed to perform all necessary analysis in an effort to determine need, cost, and benefits supporting the state regulatory requirements of its members which are necessary to substantiate funding of each member share of identified network upgrade cost responsibility.

The following pie chart summarizes the near-term network upgrades in SPP Footprint:



[176] http://www.spp.org/publications/2007%20SPP%20Transmission%20Expansion%20Plan%2020080131_BOD_Public.pdf

The specific list of these network upgrades (transmission lines and transformers) is included in the NERC master list of upgrades.

In addition to the STEP, SPP has recently completed an updated EHV Overlay Study in the beginning of 2008.

The objective of the SPP EHV Overlay Study is to develop a long range strategic assessment of the reliability, capacity and seams integration needs of the grid through the use of 345kV, 500kV and 765kV or higher transmission improvements. The study was updated to evaluate the effect of intensifying wind development activity in portions of the SPP system on the EHV recommendation that was developed in the previous EHV Overlay Study conducted in the spring of 2007. This updated EHV Overlay Study also incorporated recent decisions regarding the development of certain lines in the western portion of the SPP X-plan

The study considered four design options to meet these objectives ranging from $6.9 Billion to $7.1 Billion. All these options evaluated the combination of 765 and/or 500-345 kV option. It was determined that all of the designs provide SPP, its members and its stakeholders improved reliability for the SPP electric system while providing the ability to be a key provider of renewable energy for the Eastern Interconnection. All designs are flexible and allow for alternative interconnections to the east and for the wind collector system based upon cost, summer peak performance, export capability and losses, “Mid Point Design 2” and “Mid Point Design 4” were the top two performing options. Both terminate at the same substations for the EHV Overlay loop. The details of this study results can be found in the final study report which is available on SPP website.[177]

Operational Issues

The penetration of wind generation in the western half of SPP footprint could have a significant impact on operations due to the variable nature of this type of resource. There are currently several avenues being explored to provide transmission outlets for this energy during the next ten years such as the EHV overlay or facilities resulting from the Joint Coordinated System Plan (JCSP). However, the operational impacts to regulation and control performance that the variable generation will cause are still unknown. As the penetration rate of variable generation grows, further study will be required to mitigate any issues that arise. SPP is in process of scoping wind integration and penetration studies that will help address market/operations and planning needs associated with additional wind development in the region.

At this time, there are no known existing or upcoming environmental or regulatory restrictions that are thought to cause any impact to 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 2008–2017 assessment period, the current EIA–411 data indicates that SPP members maintain a 14.1 percent net capacity margin in 2008 down, and this margin will decrease to 8.1%

[177] http://www.spp.org/publications/Quanta_Technology_March_2_2008_Update_to_the_EHV_Study_Final_Report.pdf

percent in 2017. Based on the Bandwidth Working group report, SPP's load may vary by approximately 1.2% due to a 90/10 type of weather scenario. As mentioned before, SPP requires each member to maintain 12% capacity margin and this will address the 90/10 weather scenario. On the whole, the annual net capacity margin for SPP is greater than the required 12 percent until the year 2014, where the margin drops to 11.5 percent. The resources internal and external to the SPP region that are needed to meet the required 12% capacity margin based on the 2013 forecast total 53,860 MW and 2,789 MW respectively. For the remaining years (2014 through 2017) SPP anticipates more resources will be qualified as certain and can be counted against capacity margin in the next few years.

SPP defines firm deliverability as electric power intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin) and energy. Such power must meet standards of reliability and availability as that delivered to native load customers. Power purchased can be considered to be firm power only if firm transmission service is in place to the load serving member for delivery of such power. SPP does not include financial firm contracts towards this category

There are no significant deliverability problems expected due to transmission limitation at this time on the SPP system, However, on June 17, 2008, the western portion of the SPP footprint has experienced a system disturbance that resulted in loss of 600 MW load. In addition, SPP's EIS market continues to experience price differentials between eastern and western portion of the SPP system. SPP will continue to closely monitor the western portion of the system through the Flowgate assessment analysis. The flowgate analysis validates the list of flowgates that SPP monitors on a short term basis using various scenario models developed by the SPP Staff. These scenario models reflect all the potential transactions in various directions being requested on 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.

Also, SPP periodically conducts Loss-of-Load Expectation and Expected Unserved Energy study. The preliminary results of the ongoing study triggers additional assessment for the western portion of SPP system that includes a sensitivity of wind penetration. The final study is expected to be completed by end of 2008. Historically, SPP has adhered to a 12% regional capacity margin to ensure the minimum LOLE of 1 day in 10 years is met. Presently the 12% capacity margin requirement (both short-term and long-term) is checked annually in the EIA-411 reporting as well as through supply adequacy audits of regional members. The last supply adequacy audit was conducted in 2007 and the subsequent audit is scheduled in 2012.

SPP develops an annual SPP Transmission Expansion Plan (STEP) with regional group of projects to address regional reliability needs for the next 10 years (2008 through 2017). The latest STEP that was approved by SPP Board of Directors is available on SPP website. During the STEP process, SPP also performs a dynamic stability analysis. The latest dynamic study that was completed for the 2008 operating conditions did not indicate any dynamic stability issues for the SPP region. In addition, SPP also performs an annual review of reactive reserve requirements for load pockets within the region. Currently, SPP does not have specific criteria for maintaining minimum dynamic reactive requirement or transient voltage dip criteria.

However, according to reactive requirement study scope, which is completed as a STEP process, each load pocket or constrained area was studied to determine the available reactive reserve margin in the SPP transmission system during possible severe contingencies. This study assumes typical P-V curve characteristic where possible voltage collapse is studied when the voltage on the key buses start declining below 90%. The annual STEP process conducted by SPP did not indicate dynamic and static reactive power limited areas on the bulk power system.

SPP has an under-voltage load shedding (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 bulk power system against under-voltage events.

The significant changes from last years LTRA includes the SPP capacity margin 12% forecasted to fall below the target level in 2013. This was forecasted not to happen until 2016 in the 2007 LTRA due to the fact that more capacity was considered to calculate capacity margin. SPP members have adjusted their forecast based on the new definition of Certain capacity this year that results into a decrease in capacity margin during 2013 and beyond. However, in the next few years, SPP anticipates a significant portion 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 (0 -20%) of this capacity will be counted as Certain based on the historical trend, it would be sufficient to meet SPP's capacity margin requirement. There are no major unit retirements that are planned within the next ten years.

Due to the diverse generation portfolio in SPP, there is no concern of the fuel supply being affected by the extremes of summer weather during peak conditions. If there is to be a fuel shortage, it is communicated to SPP operations staff, in advance, so that they can take the appropriate measures SPP would assess if capacity or reserves would become insufficient due to the unavailable generation. If so, SPP would declare either EEA (Energy Emergency Alert) or OEC (Other Extreme Contingency) and post as needed on the RCIS (Reliability Coordinator Information System). SPP does not conduct operation planning study to evaluate the extreme hot weather condition. The current capacity margin criteria are intended to address the load forecast uncertainty.

Energy only, uncommitted resources and transmission–limited resources are not used in calculating net capacity margin. As previously stated, the EIA–411 data does not include the 9,892 MW of uncommitted resources that are located within the SPP footprint. These are reflected in the total potential resources capacity margin which is considerably greater than the net capacity margin. SPP staff coordinates the specific short circuit level with its members as they maintain all the latest data for the assessment period. SPP is in a process of developing a coordinated short circuit model in the later half of 2008 so that these studies can be conducted on a regional basis. There are no reliability impacts that have been addressed due to aging infrastructure and at this time SPP does not have any guideline for on-site, spare-generator step-up (GSU) and auto transformers.

SPP as a Planning Authority conducts various reliability assessments to comply with NERC TPL standards:

- TPL-001 - SPP Model Development Working Group (MDWG) ensures that all thermal and voltage violation addresses during Base Case development.
- TPL-002 - Using the SPP MDWG Models, Near and Long Term Analysis are performed by SPP staff.
- TPL-003 - SPP members submit selected N-2 contingencies that are evaluated by SPP staff.
- TPL-004 - SPP periodically conducts reactive reserve and stability study that addresses the key requirement in this standard.

Based on the studies performed, SPP is not anticipating any near-term or long-term reliability issues that have not addressed by any mitigation plan or local operating guides.

SPP has been proactive in addressing aging workforce issue in the utility industry. Since last year, SPP has sponsored a new graduate level course in Electric Power System at the University of Arkansas, Little Rock. This course focuses on the power system fundamentals with a final project targeting current industry issue. The students at the university along with SPP employees new to the power system concepts are encouraged to take this course. Also, SPP has initiated an "Engineer In Training" program in 2007. This 18 month program targets top performing students in local universities and have them rotated in various functional areas before permanent placement and assigned with specific role.

Region Description

Southwest Power Pool (SPP) region covers a geographic area of 255,000 square miles and has members in eight states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP manages transmission in seven of those states. SPP's footprint includes 17 balancing authorities and 40,364 miles of transmission lines. SPP has 50 members that serve over 4.5 million customers. SPP's membership consists of 13 investor–owned utilities, 11 generation and transmission cooperatives, 11 power marketers, 7 municipal systems, 3 independent power producers, 2 state authorities, and 2 independent transmission companies. Additional information can be found on the SPP Web site (www.spp.org).

WECC Highlights

- WECC loads are growing — the projected 2008 summer total internal demand of 162,052 MW is expected to increase by about 2.0 percent per year to 193,530 MW in 2017.
- Planning reserve margin targets (target margins) used for this report were developed using a Building Block method. These target margins ranged between 10 and 16%, with a WECC overall average of 13.7% (summer) and 12.6% (winter). The equivalent capacity margins are 12.1% and 11.2%, respectively. By 2017, reserve margins for the majority of the WECC subregions are below target margins, when using the existing plus planned resource or adjusted potential resource mix.
- The WECC target margins are in addition to serving the total load (both firm and non-firm loads).
- 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.
- Resource surpluses or deficits, aggregated into several WECC subregions (four U.S., one Canadian and one Mexican), are reported in graphs comparing loads with existing plus future resources. Descriptions of the classes of resources are provided in the generation section, Class 4 is highlighted here because it contains resources that had been identified as having been approved by corporate management or in a company's capital budget but did not meet WECC's criteria for "Planned", but Class 4 resources may meet a section of the NERC criteria for being "Planned" resources.
- The summer peak MW amounts of each of the five classes and the existing certain resources[178] (existing resources), are summarized in the following table:

Existing Resources	"Planned" Resources			"Proposed" Resources		Adjusted Proposed Resources	
As of 12/31/2007	Class 1	Class 2	Class 3	Class 4	Class 5	Class 4	Class 5
194,836	8,146	713	2,582	7,286	7,425	0	0
(Summer Rating)	Total Planned = 11,441 MW			Proposed = 14,711 MW		Adj. Proposed = 0 MW	

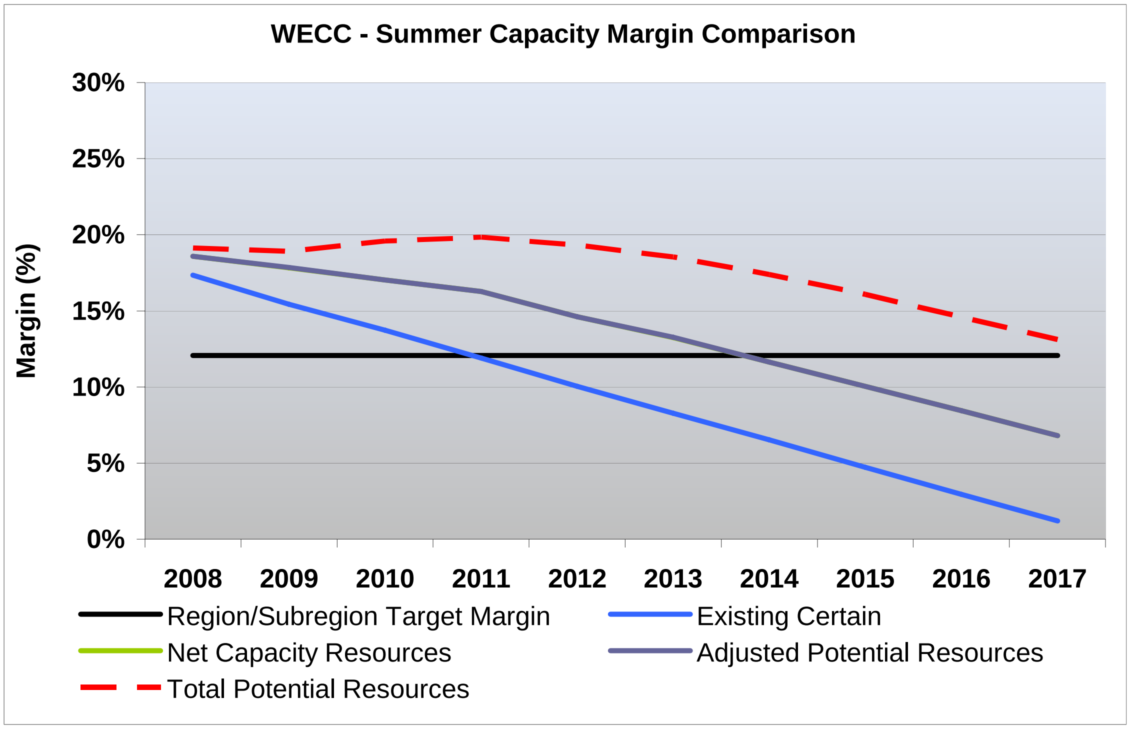
The Proposed resources or the Adjusted Proposed resources would be in addition to the Existing and Planned resources.

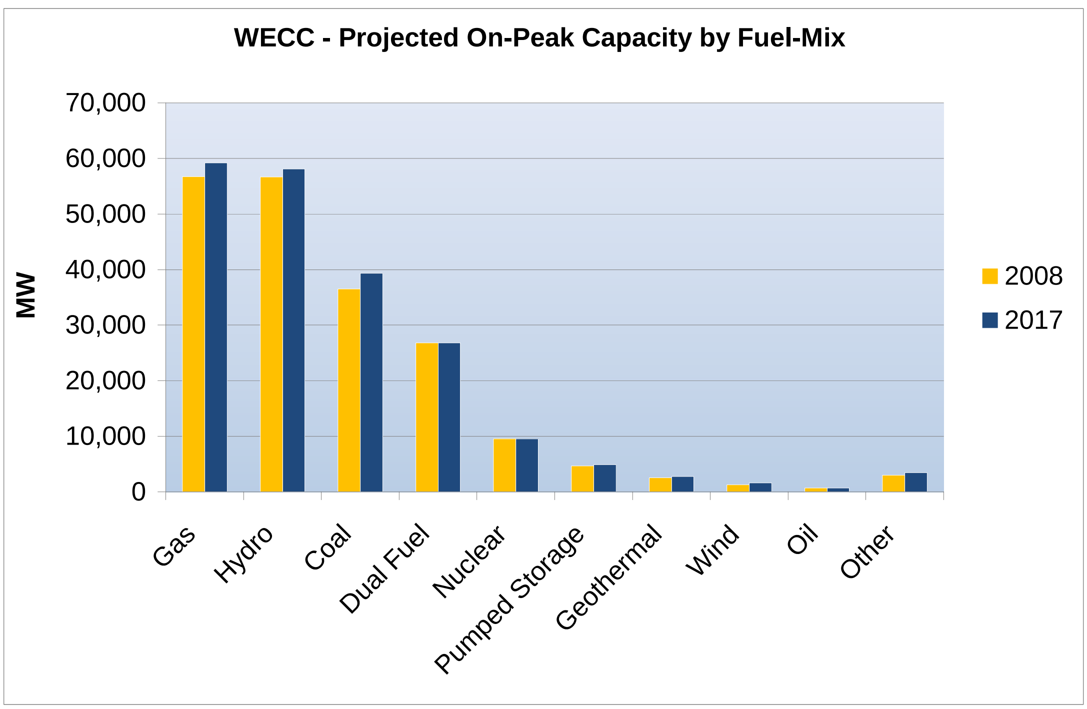
- There are several Class 4 and 5 (Proposed) projects that are short lead projects (primarily wind generation projects), that require only a short time for construction. These projects could contribute to serving loads sooner than their classification would indicate, which would increase the margins of the respective subregion(s).
- Diversity exchange transfers among subregions, as constrained by derated transmission, are assumed to meet deficits against the target margins. These transfers were submitted to NERC as Expected[179] transactions and were derived from WECC's draft 2008 Power Supply

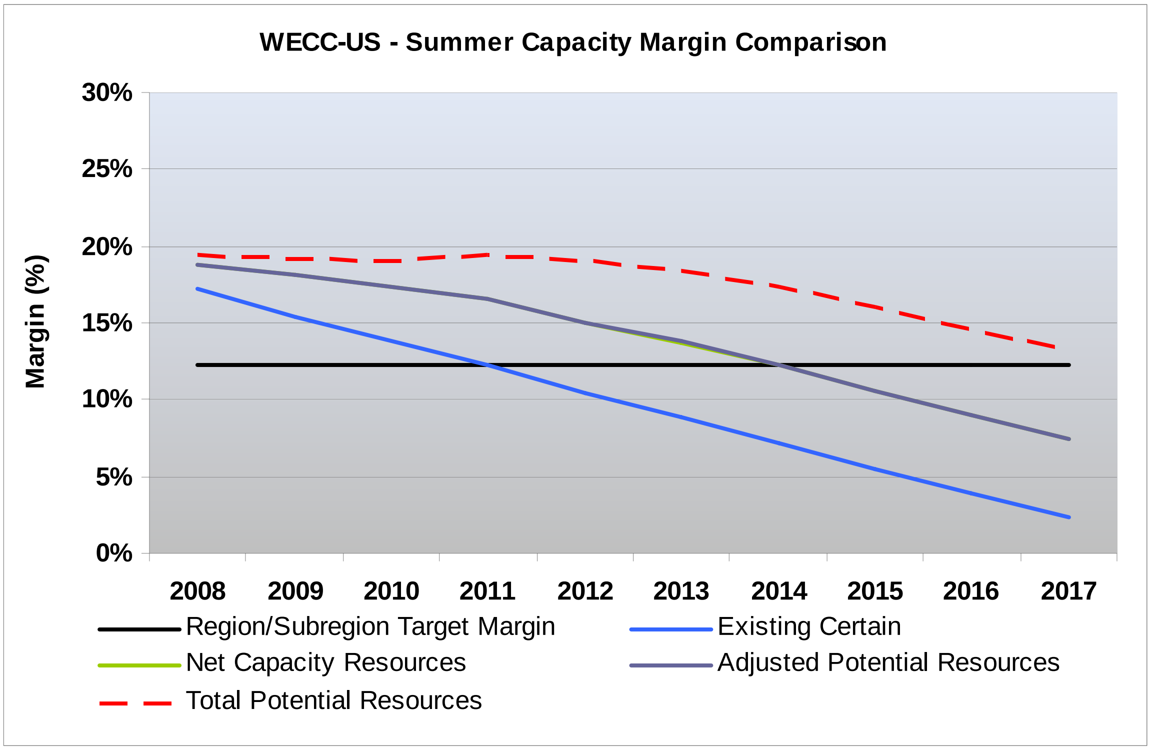
[178] NERC definition – See Appendix III Capacity and Demand Definitions
[179] NERC definition – See Appendix III Capacity and Demand Definitions

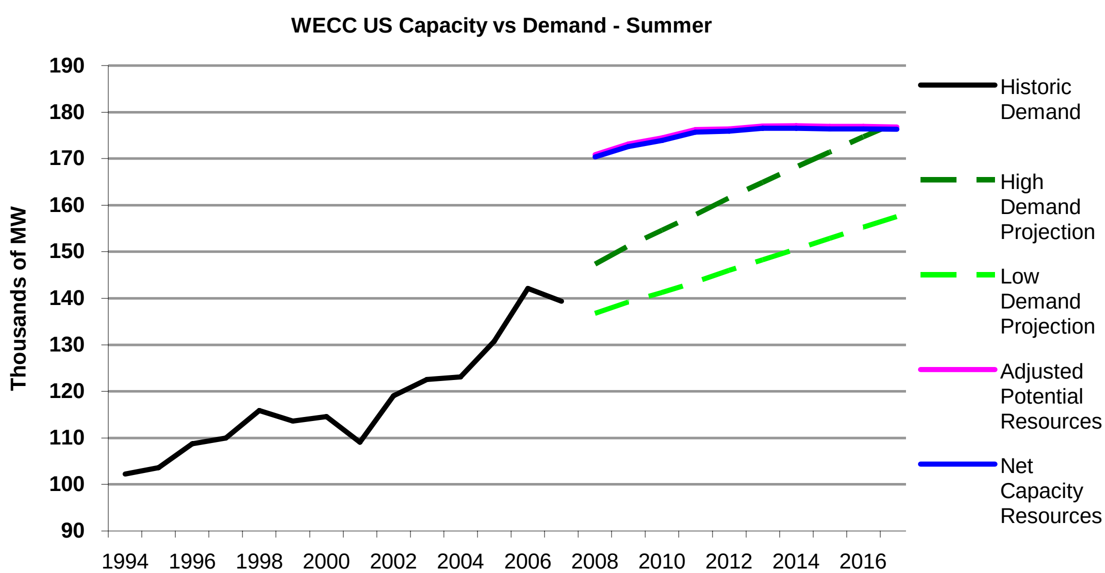
Assessment (PSA). The net capacity resources line in the margin graphics includes these transfers and transmission modeled losses.

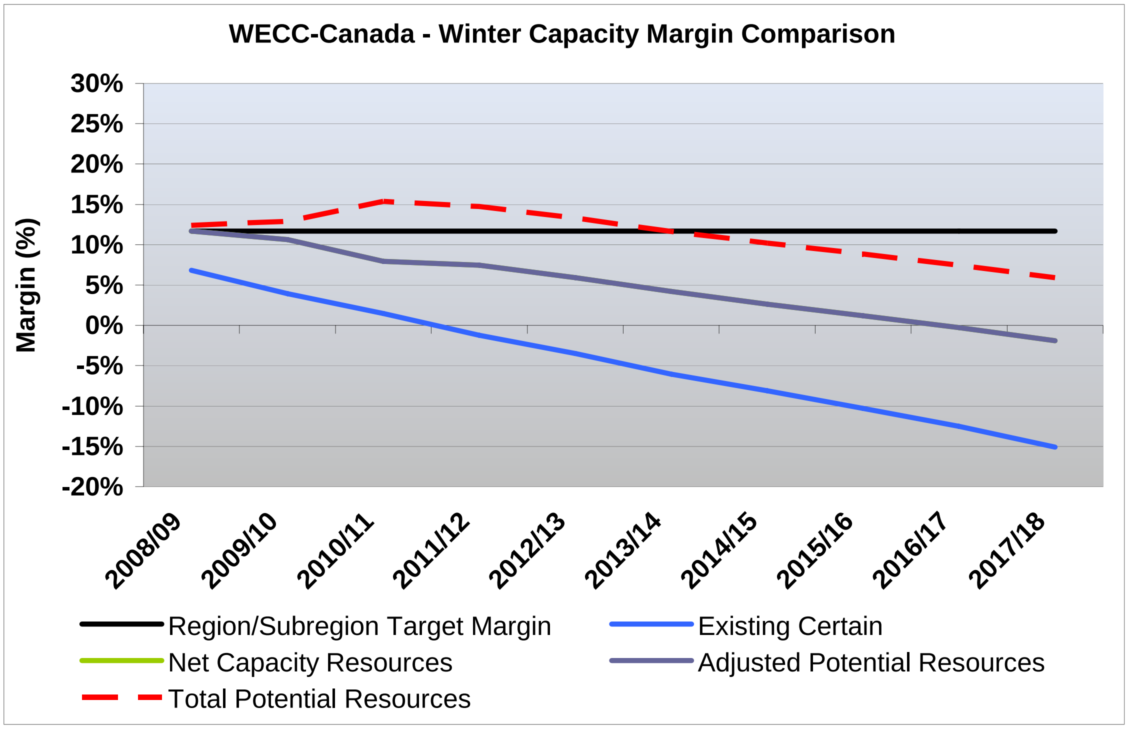
- This analysis does not include the "Proposed" resources other than to reflect the quantity in the "Total Potential Resources" line in the margin graphics and some tables. This approach was taken as the regulatory and financial status of these projects is not known at this time. WECC intends this representation to highlight the importance of investment in the future. Resources, either currently identified or unknown, need to move deliberately into development as deficits approach and as project development timelines dictate.
- When only considering "planned" resources and transfers, the Northwestern Power Pool - Canada subregion goes below the WECC developed target margin for that subregion, as early as the winter of 2009-2010. One of the NWPP-CN provinces has indicated that there are several short lead projects that have been classified by WECC as class 4 or 5 that are scheduled to be in-service by the winter of 2009-2010. It is anticipated that with those projects the NWPP-CN margin will be close to the target margin for that subregion.
- By the summer of 2017, the difference between WECC's Net Capacity Resources (202,379 MW) and WECC's Total Internal Load (193,530 MW) would be 8,849 MW (4.6% reserve margin), if there were no transmission constraints. This would be 17,054 MW below the desired target margin. This included serving 4,898 MW of Demand-Side-Management (DSM) load. If the DSM load were not to be served it would result in a 7.3% reserve margin. When looking at subregions, or a region overall, it may be a concern to only consider the Net Internal Demand (Total Internal Demand minus DSM programs) when determining margins, because the DSM programs are generally not sharable between balancing authorities, subregions or regions, some have a limited number of times they can be called upon and some can only be called upon during a declared emergency.
- Margin results from the PSA were used to derive expected inter-subregion transfers. In the PSA, conservative transmission limits were placed on paths between the 26 PSA load groupings (bubbles) and were observed when calculating the transfers between these bubbles. The aggregation of PSA load bubbles into LTRA reporting subregions may obscure differences in adequacy or deliverability between bubbles in the subregion. Deficits below planning reserve targets (while serving total load) begin to emerge toward the end of this decade. Including Classes 1 through 3, summer electricity supply shortages relative to planning summer reserve targets could occur as early as 2010 in the desert southwest, and Mexico area and winter electricity supply shortages relative to planning winter reserve targets could occur as early as 2009-2010 in Canada as mentioned above.
- The analysis is based on loads and resources data submitted in December 2007 and February 2008. The reported data was "locked" on March 31, 2008, and project changes reported to WECC after the data was locked were not included in the studies. For instance, it does not appear that the two Holcomb coal plants that were reported by WACM will be constructed by the time reported. However, this was learned after the data was locked and the effects of the Holcomb units can be seen in the RMPA area. Salt River Project in the AZ-NM-SNV subregion has announced plans for several natural gas generating units, but these additions were announced after the data was locked and were therefore not included in this study, in order to be consistent with other studies that are being performed.

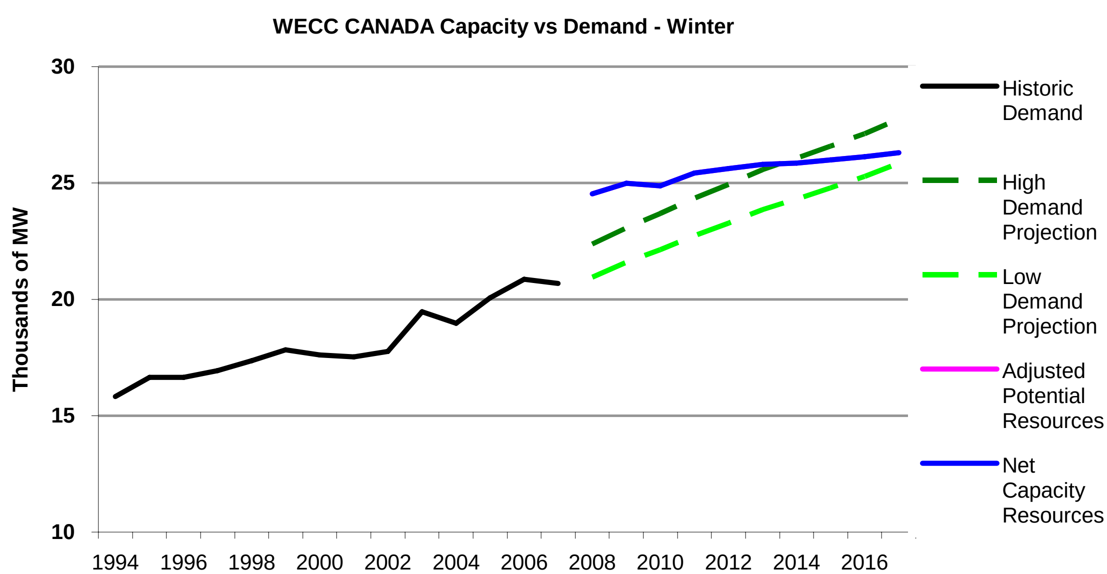

WECC - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

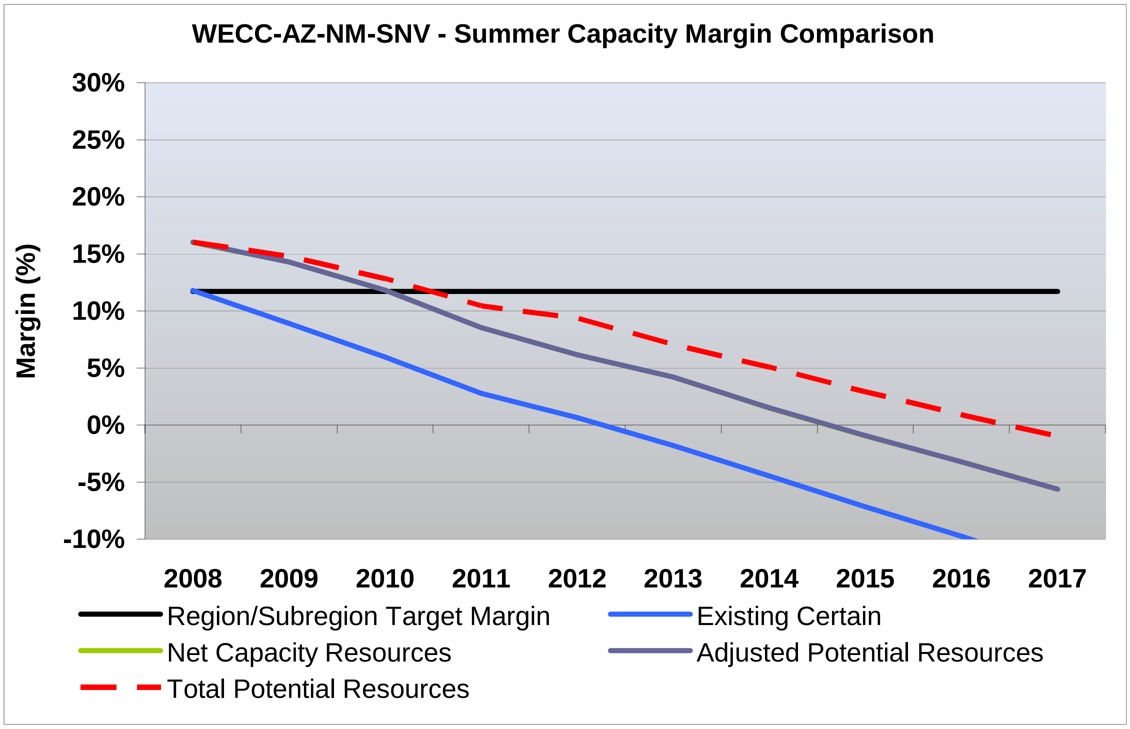

WECC - Projected On-Peak Capacity by Fuel-Mix
MW
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Gas
Hydro
Coal
Dual Fuel
Nuclear
Pumped Storage
Geothermal
Wind
Oil
Other
2008
2017

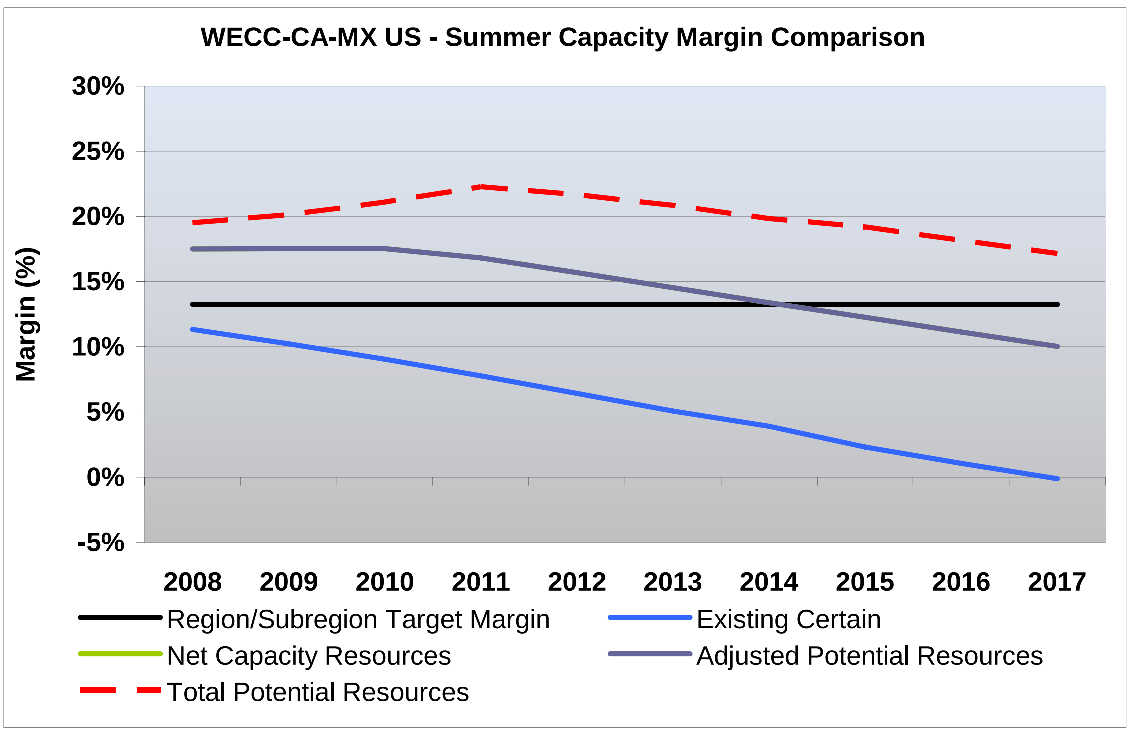

WECC-US - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

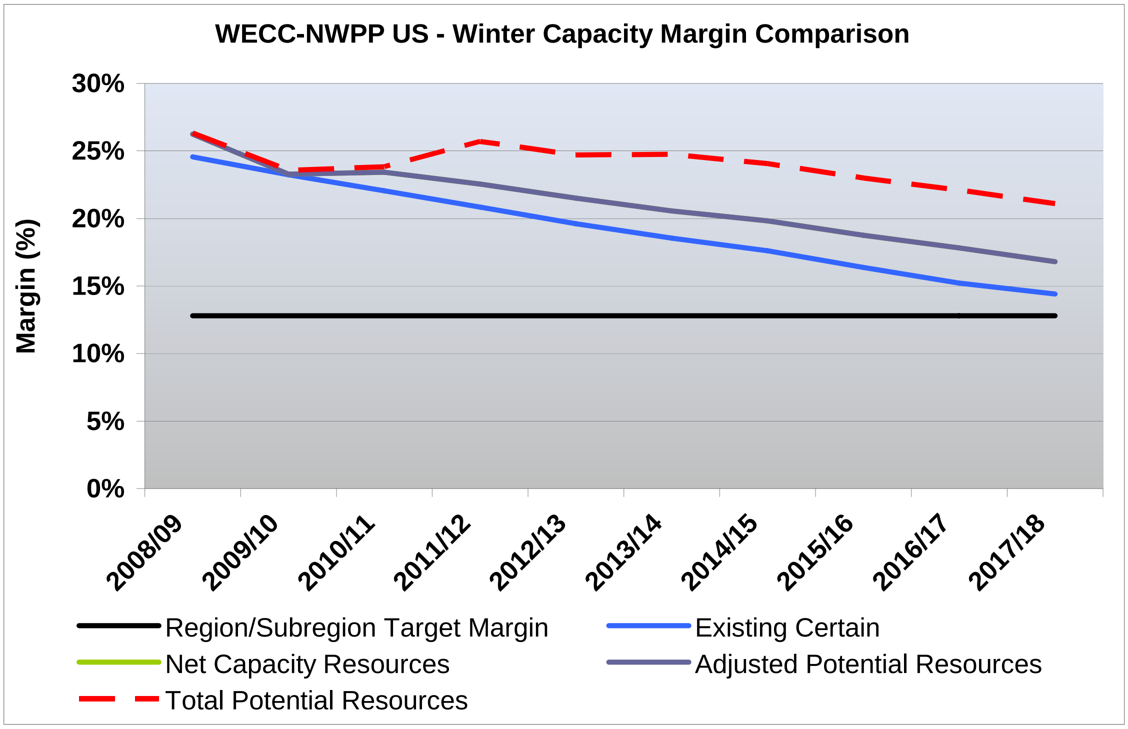

WECC US Capacity vs Demand - Summer
Thousands of MW
190
180
170
160
150
140
130
120
110
100
90
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources

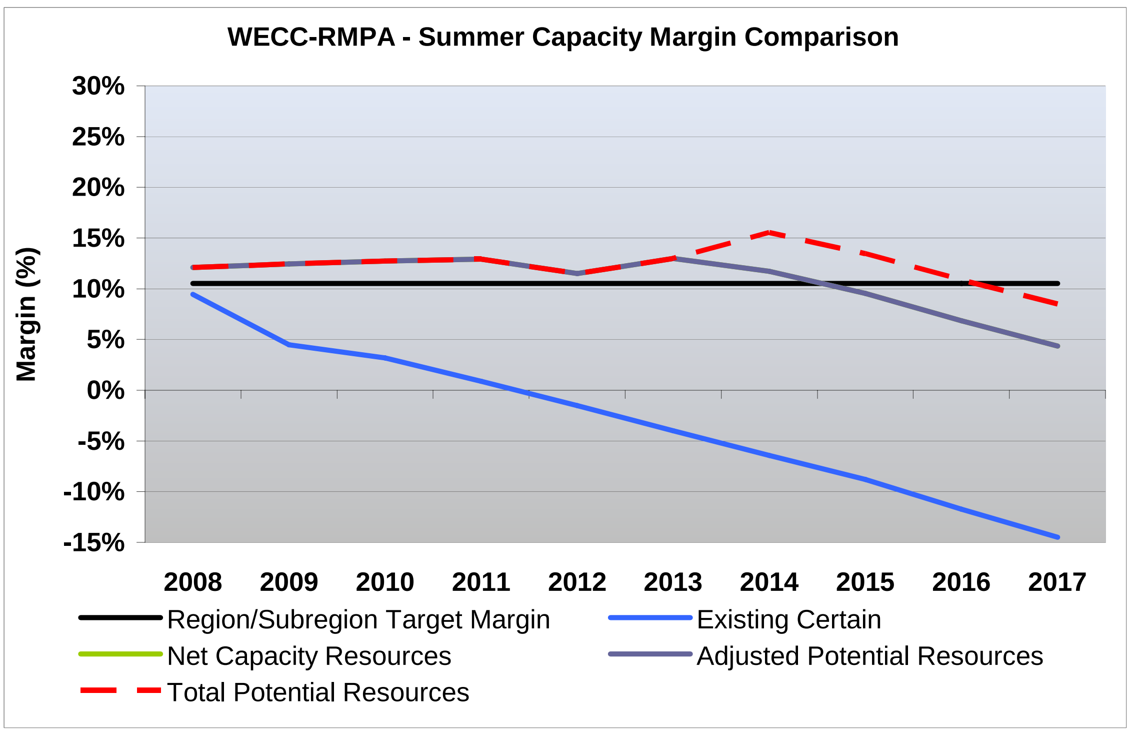

WECC-Canada - Winter Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

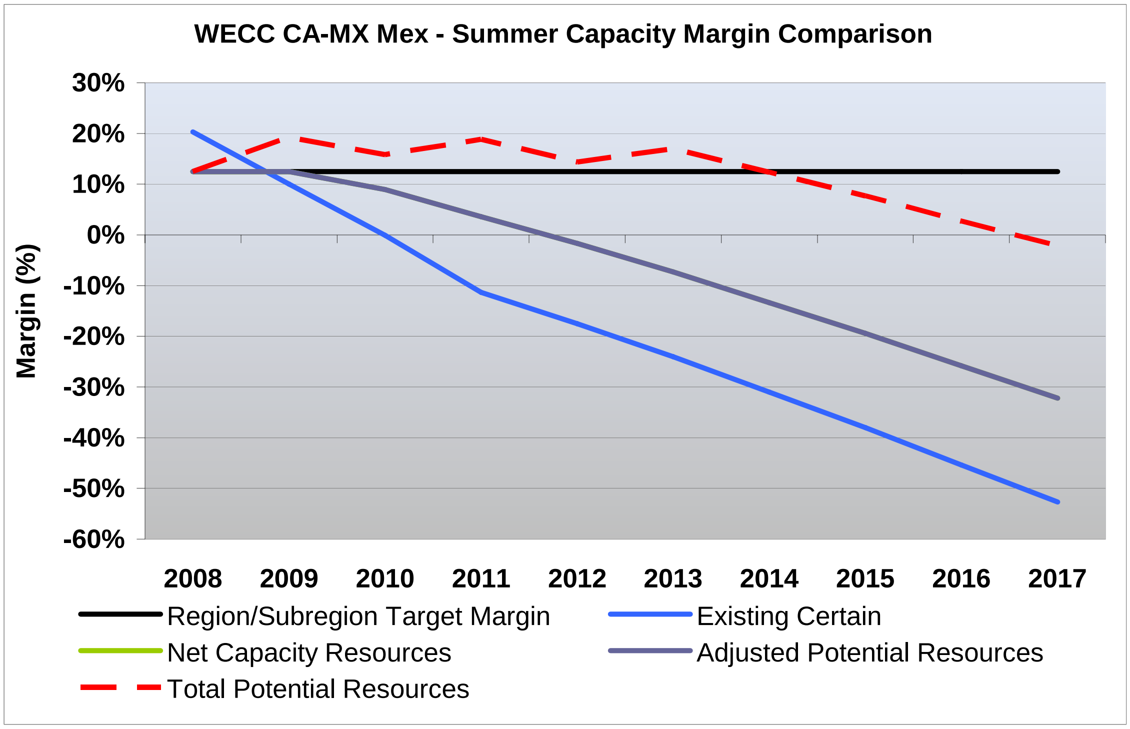

WECC CANADA Capacity vs Demand - Winter
Thousands of MW
30
25
20
15
10
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
Historic Demand
High Demand Projection
Low Demand Projection
Adjusted Potential Resources
Net Capacity Resources


WECC-AZ-NM-SNV - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
-10%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


WECC-CA-MX US - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


WECC-NWPP US - Winter Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


WECC-RMPA - Summer Capacity Margin Comparison
Margin (%)
30%
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources


WECC CA-MX Mex - Summer Capacity Margin Comparison
Margin (%)
30%
20%
10%
0%
-10%
-20%
-30%
-40%
-50%
-60%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Region/Subregion Target Margin
Existing Certain
Net Capacity Resources
Adjusted Potential Resources
Total Potential Resources

WECC Self-Assessment

Peak Demand

Total actual internal demand decreased by 1.8 percent from 2006 to 2007. Summer temperatures in 2006 were much warmer than normal and summer temperatures in 2007, were generally normal to somewhat above normal. The projected aggregate WECC 2008 summer total internal demand is forecast to be 162,052 MW (U.S. systems 142,032 MW, Canadian systems 17,907 MW, and Mexican system 2,223 MW) which is an expected 2.45 percent increase from the 2007 actual demand of 158,178 MW. The anticipated rate of growth for the long term is essentially unchanged changed from last year. The summer total internal demand is expected to increase by about 2.0 percent per year for the 2008-2017 timeframe which is the same as the 2.0 percent projected last year for the 2007-2016 period.

SUMMER PEAK GROWTHS				
	WECC	WECC US	WECC CN	WECC MX
2007 Actual	158,178	139,389	17,265	2,153
2008 Projected	162,052	142,032	17,907	2,223
Growth %	2.45%	1.90%	3.72%	3.25%
2017 Projected	193,530	167,661	22,489	3,598
2008 – 2017 Growth %	1.99%	1.86%	2.56%	5.50%

WECC specifically directs its balancing authorities (BAs) to submit forecasts with a 1 year in 2 probability of occurrence; most of the entities based their forecasts on population growth, economic conditions and normalized weather such that there is a 50% probability of exceeding the forecast (i.e., 1 in 2). WECC has not established a quantitative analyses process for assessing the variability in projected demands due to the economy.

The internal peak demand forecasts presented here are a non-coincident sum of the forecasted demands from WECC's 35 BAs. Comparisons with hourly demand data indicate that WECC non-coincident peak demands generally exceed coincident peak demands by two to four percent. The entities within the Balancing Authorities use various peak forecasting methods that range from not making any 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) model 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., 1 year in 5, 1 year in 10 conditions) for other internal planning purposes. Econometric models used by various entities within the Western Interconnection, consider rate effects, average area population income, etc.

Within the WECC region and its subregions there is a mixture of demand response programs. Demand response programs have several different types but they usually fall into two categories: 1) Passive DSM programs such as encouraging end-users, through economic incentives, high efficiency lighting, heat pumps, and water heaters as well as home insulation improvements and in some cases the planting of shade trees which help manage demand and energy growth in commercial and residential areas; 2) Active DSM programs. A key difference in some of these programs is whether the program is dispatchable by the BA. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions and are not under the control of the customer and cannot be anticipated by the customer. WECC has historically only gathered data on these traditional Demand Side Management (DSM) programs (Dispatchable Load Management air conditioners etc. and interruptible loads). For the 2008 LTRA, WECC requested further information on DSM programs from the BAs, if applicable. The various dispatch operator direct controlled programs reported are largely: interruptible demand and direct control load management (air conditioning management), some of which have specific criteria that must be met prior to be called upon. There are also other DSM programs i.e., critical peak pricing, demand bidding and others that are customer activated after receiving some form of notification from a control center.

The total WECC internal demand forecast includes demand response and interruptible loads that range from 4,107 MW in 2008 to 4,898 MW by 2017. The direct control demand-side management capability is located mostly in California (3,281 MW), but the other subregions' DSM programs are increasing. Much of the demand response in WECC is based on air conditioner cycling programs. Interruptible load programs are more focused on large water pumping operations and large commercial operations such as mining.

Generation

WECC's resource data excludes non-metered self-generation and expected wind and hydro limitations. The data for the LTRA is provided by all of the balancing authorities within the Western Interconnection and is processed by WECC's Staff under the direction of WECC's Loads and Resources Subcommittee (LRS).

This year NERC redefined its resource classifications as shown in the Capacity & Demand Definitions section in the back of this document. As mentioned in earlier, WECC's LRS chose to classify the future capacity resources into five classes that help provide greater definition and granularity, instead of NERC's two classifications (Planned and Proposed). The five class definitions are to be used in both WECC's Self-Assessment for this LTRA and the Power Supply Assessment (PSA) analyses. The class descriptions and using January 1, 2008 as the starting point, the 2017 megawatt totals for each class are:

Class 1: Under active construction and projected in service by Jan. 2012 (8,146 MW).

Class 2: All regulatory permits approved and Interconnection agreement signed and projected to be on-line by Jan. 2014 (713 MW).

Class 3: At least under regulatory review and at least facility study done and interconnection agreement in active negotiation and projected to be on-line by Jan. 2014 (2,582 MW).

Class 4: All other resources that meet NERC criteria for "Planned" resources. This is intended to capture those "Planned" resources that qualify only through meeting the management approval criterion, which LRS does not believe carries a similar degree of commitment or likely construction outcome as the other criteria in the "Planned" category (7,286 MW).

Class 5: All other resources that meet NERC criteria for "Proposed" resources (7,425 MW).

"Planned" Resources			"Proposed" Resources	
Class 1	Class 2	Class 3	Class 4	Class 5
8,146	713	2,582	7,286	7,425
Total Planned = 11,441 MW			Proposed = 14,711 MW	

The following four tables reflect the WECC existing and "Planned" resources by generation classification and subregion, for the study period for the both non-derated capacity and summer on-peak capacity.

EXISTING RESOURCES AS OF 12/31/2007 SUMMER RATINGS - NON DERATED -	NORTHWEST POWER POOL AREA	ROCKY MOUNTAIN POWER AREA	ARIZONA NEW MEXICO SO. NEVADA POWER AREA	CALIFORNIA MEXICO POWER AREA	WECC TOTAL	PERCENT OF TOTAL
HYDRO - CONV. & PUMPED	49,126	1,426	4,700	14,008	69,260	30.2%
THERMAL	33,757	11,307	30,990	44,343	120,397	2.5%
NUCLEAR	1,150	0	3,872	4,530	9,552	17.1%
GEOTHERMAL	180	0	450	2,255	2,885	1.4%
INTERNAL COMBUSTION	211	253	0	49	513	0.2%
BIOMASS	639	2	58	1,120	1,819	0.9%
SOLAR	0	8	49	458	515	0.2%
WIND	3,243	662	295	2,374	6,574	3.1%
OTHER	174	0	53	535	762	0.4%
TOTAL	88,480	13,658	40,467	69,672	212,277	100.0%
PERCENT OF WECC TOTAL	41.7%	6.4%	19.1%	32.8%	100.0%	

EXISTING RESOURCES AS OF 12/31/2007 SUMMER PEAK RATING	NORTHWEST POWER POOL AREA	ROCKY MOUNTAIN POWER AREA	ARIZONA NEW MEXICO SO. NEVADA POWER AREA	CALIFORNIA MEXICO POWER AREA	WECC TOTAL	PERCENT OF TOTAL
HYDRO - CONV. & PUMPED	43,160	1,310	4,070	12,787	61,327	31.5%
THERMAL	33,757	11,307	30,990	41,484	117,538	60.3%
NUCLEAR	1,150	0	3,872	4,466	9,488	4.9%
GEOTHERMAL	180	0	450	1,876	2,506	1.3%
INTERNAL COMBUSTION	211	253	0	27	491	0.3%
BIOMASS	639	2	58	570	1,269	0.7%
SOLAR	0	4	49	347	400	0.2%
WIND	596	80	1	490	1,167	0.6%
OTHER	174	0	53	423	650	0.3%
TOTAL	79,867	12,956	39,543	62,470	194,836	100.0%
PERCENT OF WECC TOTAL	41.0%	6.6%	20.3%	32.1%	100.0%	

WECC has 194,836 MW of Existing Certain resources as of 12/31/2007, including the anticipated summer on-peak values (de-rated) of approximately 1,167 MW from wind, 400 MW from solar, 1,269 MW from biomass and 61,327 MW of hydro (56,646 MW of conventional hydro, 4,681 MW of pumped storage hydro). The Existing Uncertain[180] resources for 2008 are

[180] See *Capacity, Demand & Event Definitions* Section of this report

5,407 MW of wind, 115 MW of solar, 550 MW of biomass, 7,933 MW of hydro (7,369 MW of conventional hydro, 564 MW of pumped storage hydro) and 2,472 MW of inoperable for a total of 16,477 MW. The non-derated values for the existing variable resources can be seen above.

FUTURE "PLANNED" RESOURCES NON-DERATED RATING	NORTHWEST POWER POOL AREA	ROCKY MOUNTAIN POWER AREA	ARIZONA NEW MEXICO SO. NEVADA POWER AREA	CALIFORNIA MEXICO POWER AREA	WECC TOTAL	PERCENT OF TOTAL
HYDRO - CONV. & PUMPED	1,416	0	0	97	1,513	11.0%
THERMAL	1,902	2,111	1,952	2,684	8,649	62.9%
NUCLEAR	0	0	71	0	71	0.5%
GEOTHERMAL	156	0	0	107	263	1.9%
INTERNAL COMBUSTION	-44	112	0	118	186	1.4%
BIOMASS	96	4	56	50	206	1.5%
SOLAR	0	0	280	0	280	2.0%
WIND	1,566	449	0	566	2,581	18.8%
OTHER	0	0	0	1	1	0.0%
TOTAL	5,092	2,676	2,359	3,623	13,750	100.0%
PERCENT OF WECC TOTAL	37.0%	19.5%	17.2%	26.3%	100.0%	

FUTURE "PLANNED" RESOURCES SUMMER PEAK RATING	NORTHWEST POWER POOL AREA	ROCKY MOUNTAIN POWER AREA	ARIZONA NEW MEXICO SO. NEVADA POWER AREA	CALIFORNIA MEXICO POWER AREA	WECC TOTAL	PERCENT OF TOTAL
HYDRO - CONV. & PUMPED	1,416	0	0	200	1,616	14.1%
THERMAL	1,902	2,111	1,952	2,438	8,403	73.4%
NUCLEAR	0	0	71	0	71	0.6%
GEOTHERMAL	156	0	0	107	263	2.3%
INTERNAL COMBUSTION	-44	112	0	113	181	1.6%
BIOMASS	96	4	56	39	195	1.7%
SOLAR	0	0	280	0	280	2.4%
WIND	250	56	0	125	431	3.8%
OTHER	0	0	0	1	1	0.0%
TOTAL	3,776	2,283	2,359	3,023	11,441	100.0%
PERCENT OF WECC TOTAL	33.0%	20.0%	20.6%	26.4%	100.0%	

In the above two Planned tables it should be noted that in some resources the non-derated value did not increase as much as the summer peak rating. This can be due to a Planned action taking place on an existing resource, such as a reduction to the summer de-rates. A negative value in the summer peak rating table may be due to deratings of existing units or the mothballing or retirement of a unit.

The Planned capacity resources (Classes 1 through 3) projected to be in-service by the end of this assessment period is 11,441 MW. Included in that value are 431 MW of wind, 280 MW of solar, 195 MW of biomass and 1,616 MW of hydro. The non-derated values for these can also be seen in the above tables.

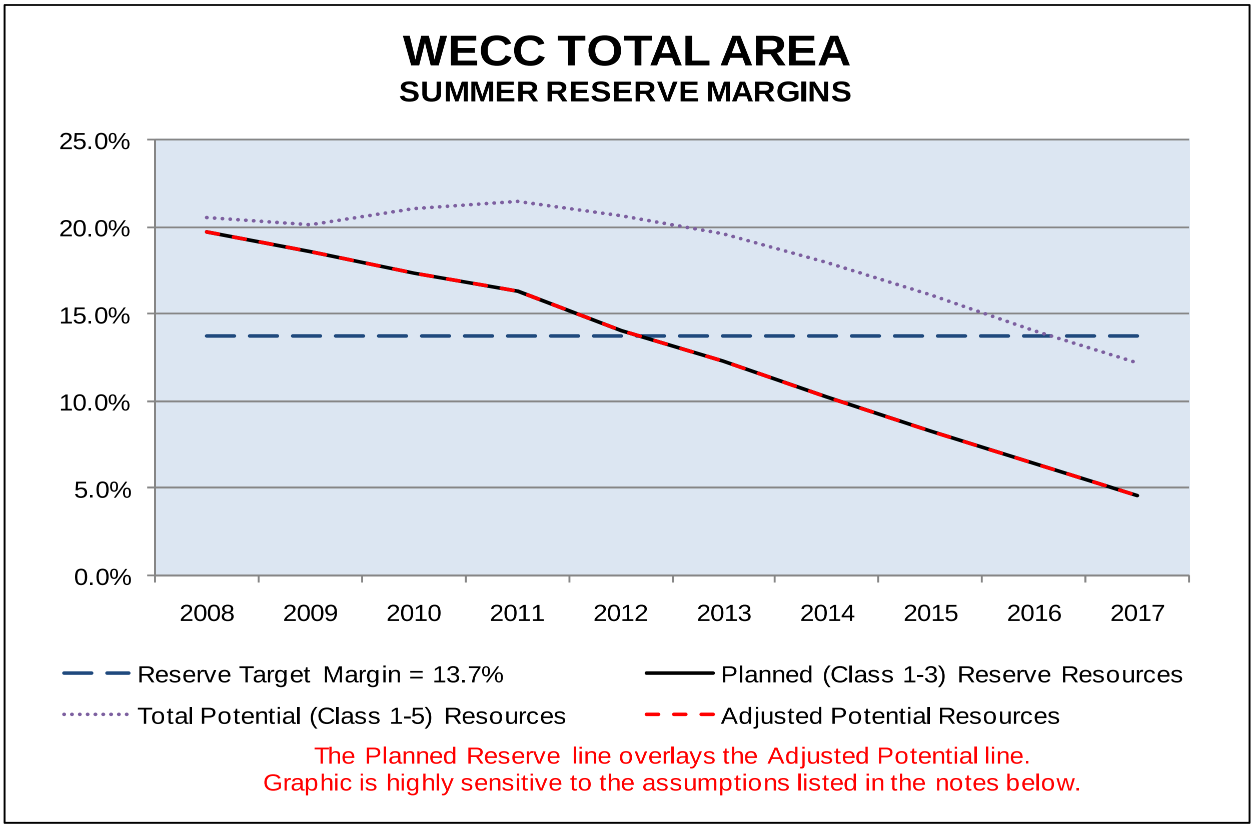
WECC is using its defined “Planned” resources (11,441 MW) in its PSA as the basis for determining the expected transfers used in this LTRA to reflect diversity exchanges. Classes 4 and 5 (14,711 MW) resources are considered “Proposed” resources but are reduced to zero when a zero percent confidence factor assigned to them. They appear in the graphics in the Total “Potential” line but are reduced to the “Adjusted Potential” line when the confidence factor is applied.

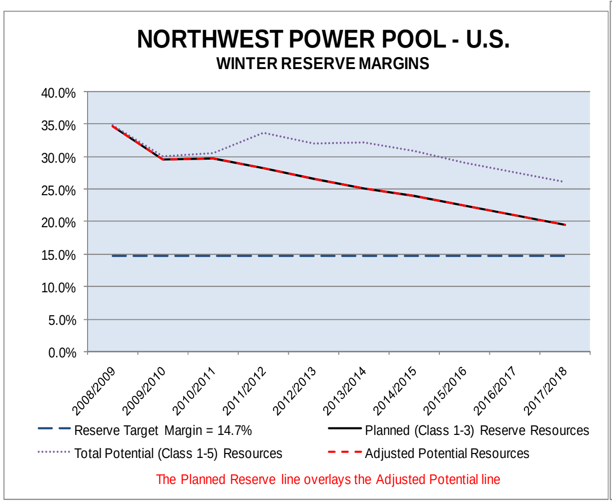
When analyzing the entire WECC, there are various items that may misrepresent the actual condition or resource adequacy. Two of the primary items are:

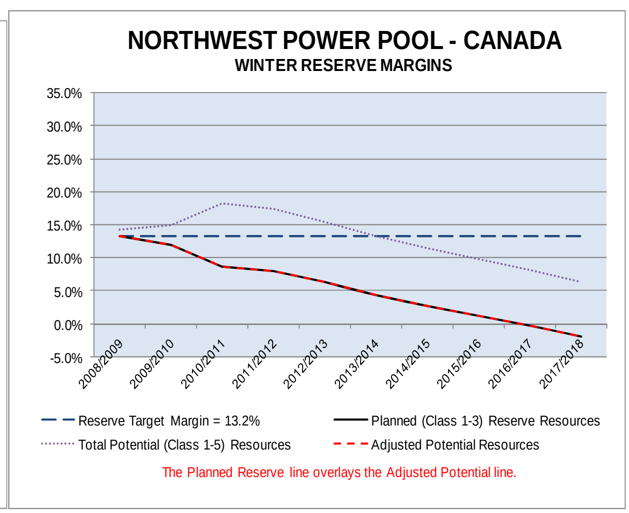
1) Neither the summer nor the winter analysis for the Northwest sub-region fully captures the limitations on the ability of the Northwest hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses, both to meet

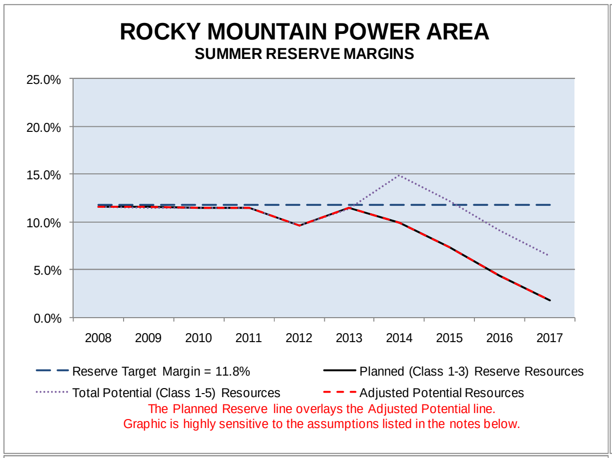
Northwest load and for potential export to other subregions of the West, may be unrealistically high.

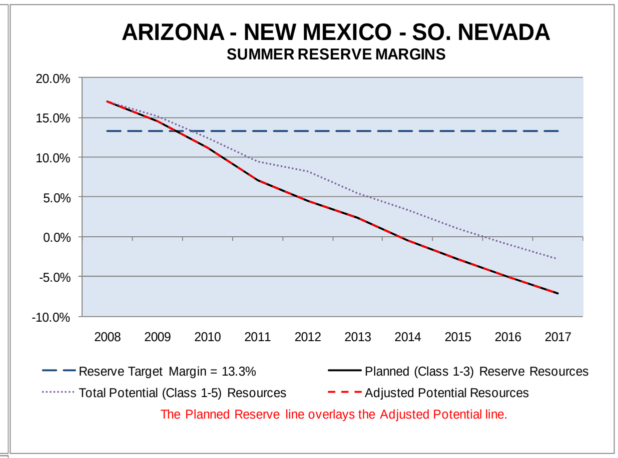
2) Looking at the Net Internal Demand (Total Demand minus Demand Side Management (DSM) programs) of WECC, when DSM programs are not sharable between the various subregions and in some cases not even within the subregion. The graphics below only considers the Net Internal Demand when initially calculating the quantity of capacity that should be above the total demand.

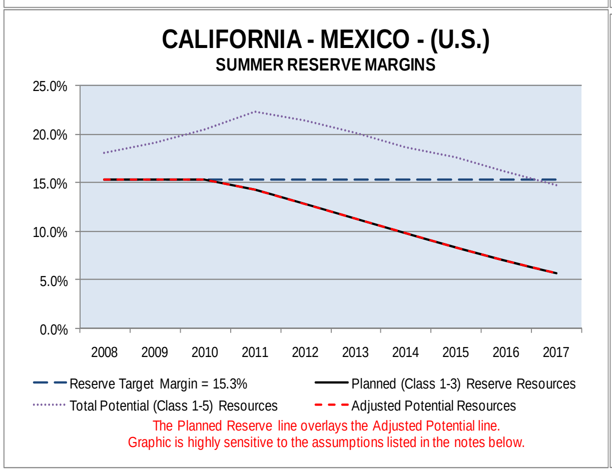


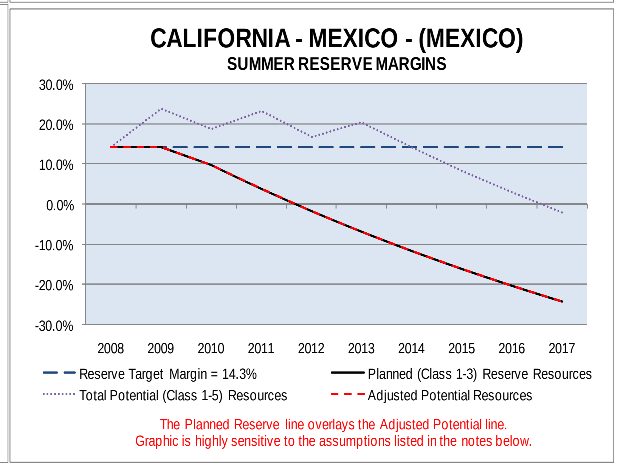












Note: These graphics reflect assumptions that are highly sensitive related to: Assignment of resources to class; Renewable energy resource derates or limitations; Inter-subregion diversity exchanges or power transfers; and the ability to share Demand Side Management programs between Balancing Authorities. Changes in these inputs may affect the results significantly.

Chart 1—Summer Reserve Margins: WECC Region.
Chart 2—Winter Reserve Margins; Northwest Power Pool (NWPP) (both the U.S. and Canada)
Chart 3—Winter Reserve Margins; Northwest Power Pool (NWPP-CN) (Canada only)
Chart 4—Reserve Margin: Rocky Mountain Power Area (RMPA)
Chart 5—Reserve Margin: Desert Southwest Area (DSWA) or Arizona-New Mexico-So. Nevada (AZ-NM-SNV)
Chart 6—Reserve Margin: California-Mexico Total Area (CAMX) (both the U.S. and Mexico)
Chart 7—Reserve Margin: California-México (México) Area (CAMX-MX)

The graphics above and throughout the rest of the WECC self assessment are shown using reserve margins versus the NERC graphics (after the WECC highlights) which uses capacity margins. The difference of reserve margins versus capacity margins is the denominator. Both the reserve and capacity margins usually have the same numerator (the sum of the net capacity resources (including transfers) minus the net demand), but for the reserve margin you divide the numerator by the net demand versus dividing by the net capacity resources for the capacity margin. WECC used the total demand instead of the net demand due to concerns of sharability of DSM programs as mentioned earlier. Because the targeted capacity will be bigger than the load, the capacity margin calculation will give a smaller percentage value than the reserve margin for the same MW value as seen in the Table of Target/Planning Margins.

Table of Target Margins

Summary of Target Margins

	WECC	WECC-US	NWPP	NWPP-CN	NWPP-US	RMPA	AS-NM-SNV	CAMX	CAMX-US	CAMX-MX
Summer Reserve Margin	13.73%	14.03%	13.52%	13.52%	11.31%	11.76%	13.27%	15.28%	15.28%	14.25%
Summer Capacity Margin	12.07%	12.30%	11.91%	11.91%	10.16%	10.53%	11.72%	13.25%	13.25%	12.47%
Winter Reserve Margin	12.92%	12.89%	14.20%	14.69%	13.24%	13.36%	12.77%	11.04%	11.06%	10.35%
Winter Capacity Margin	11.44%	11.42%	12.44%	12.81%	11.69%	11.79%	11.32%	9.94%	9.96%	9.38%

Example: In July of 2008, the DSWA projected Net Load is 30,996 MW and a Total Load of 31,551MW therefore the required Reserve margin then would be:

Typical Reserve Margin target method: Apply Reserve Margin %: 13.27% x 30,996 = 4,113 MW

Calculate Target Capacity desired: 30,996 + 4,113 = 35,109 MW

Typical Capacity Margin method: Capacity Margin: (35109 - 30996) / (35109) = 11.71%

WECC Reserve Margin Target Method: Apply Reserve Margin %: 13.27% x 30,996 = 4,113 MW (based on net demand) except California

Calculate Target Capacity desired for WECC (serving total load): 31,551 + 4,113 = 35,664 MW

Recalculated reserve margin percent (reserve plus total load): (35664 - 30996) / (35664) = 13.09%

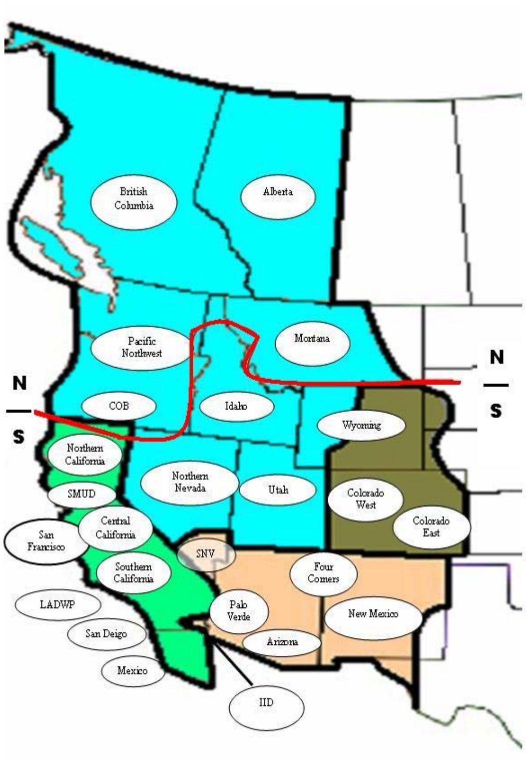
Note: On some of the graphics it may be seen that the calculated reserve margin may be parallel but slightly less than the Target Margin, this is due to the above difference. For the California-Mexico subregion, the reserve margin % was applied to the total load.

The "Target" reserve margins in the above table, are derived from the Planning Reserve Margins that are used in WECC's Power Supply Assessment (PSA). The PSA uses a "building block" method for developing Planning Reserve Margins. The building block approach has four elements: contingency reserves, regulating reserves, reserves for additional forced outages, and reserves for 1-in-10 weather events. The building block values were developed for each balancing authority and then aggregated by subregions and the entire WECC for the PSA and this LTRA analysis. The aggregated summer season Planning Reserve Margin (not Capacity Margin) for WECC was 13.73% as calculated for the 2008 PSA. This reserve margin maybe lower or higher than some of the state, provincial or Load Serving Entity (LSE) requirements within WECC, but was developed specifically for use in the PSA and LTRA.

In the above graphs, the "Net Capacity Resources" margin line equals the sum of Planned resources (Classes 1, 2 and 3) plus the Existing Certain resources plus the net transfers of both firm and Expected transfers. The "Total Potential Resource" line equals the sum of the Net Capacity Resources plus the Existing Uncertain Capacity (cold standby/mothballed units, etc.) plus "Proposed Capacity" (Classes 4 and5). The "Adjusted Potential Resources" line equals the formula used above for the Total Potential Resource line, but the "Proposed Capacity" is multiplied by an estimated certainty factor (which WECC has assigned a zero value) and results in nearly the same values as the "Net Capacity Resources."

The pool of supply/demand side resource options come from a variety of sources including forward markets, self-build projects, merchant plants and RFP responses.

The processes used by the LSEs and BAs to select resources for internal reliability analysis/capacity margin calculations vary throughout WECC. Some of the processes used to evaluate the needs for more resources are: forward capacity markets and resource adequacy needs; obligation to serve activities; low certainty classes of resources under consideration, etc. Many of the entities within WECC use formal RFPs, review resource mix, evaluate fuel diversity environmental impacts, and/or look at the need to add new generation for meeting actual and prospective state and federal mandated "renewable portfolio standards".



The preliminary 2008 PSA shows congestion within some of WECC's subregions, i.e., Mexico (CAMX-MX) and the Desert Southwest Area (AZ-NM-SNV) beginning in July 2010. A condition called the "North-South split" occurs when the transmission system between the COB intertie, the Pacific Northwest, British Columbia and Montana (the North) and the areas to the south (the South) is insufficient to allow all reported surpluses north of the constraint to meet loads south of the constraint in the economic dispatch performed in SAM. The North-South split occurs within the Northwest subregion but affects all the southern subregions of WECC.

The PSA does not indicate transmission limitations going from the DSWA into California perhaps due to the projected lack of excess resources in the DSWA. Because the transfers between subregions are calculated using the derated capacity of wind generators, additional transfers, from this or other generation, may be blocked by inadequate transmission capacity. The extent of these additional potential transfers is unknown and was not considered in the PSA analysis. WECC has not established an interconnection-wide process to address the issue of planning for variability in resource availability due to fuel or hydro limitations and other conditions.

Purchases and Sales on Peak

For the summer of 2008, WECC entities report net firm imports from Eastern Interconnection entities of 467 MW, composed of 614 MW of gross imports and 147 MW of gross exports. By the summer of 2017, imports decline to 301 MW and exports have risen to 182 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 are not modeled.

The resource data for the individual subregions include transfers between subregions that are either firm or projected potential economic transfers with a high probability of occurrence. The firm transfers represent both firm purchases or sales and Joint Plant transfers (distribution of generation from facilities that have multiple owners) from one subregion to another.

The projected potential 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 the western market. These potential transactions, internal transfers within the region, were simulated in WECC's preparation for the 2008 PSA and are reported as Expected purchases or sales and are included in the Net Capacity Resources line on the subregional capacity graphs. The modeling for the PSA is performed using a modified least cost dispatch program called the Supply Adequacy Model (SAM). SAM, which was developed by the California Energy Commission calculates transfers that are physically possible and economically justifiable (basic transmission costs and losses and generation costs), but they do not reflect any underlying contractual or other commitments.

Despite the fact that these transactions are not contracted, they have a high probability of occurrence, given the history and extensive activity of the Western market and the otherwise underused transmission from the Northwest to the other subregions. The preliminary 2008 PSA studies show that the North-South Split first occurs in July of 2010. at which time it shows both Mexico and the Desert Southwest Area going below the sum of the total internal load plus the specific planning reserve for those areas. For the LTRA results from the PSA were observed. In the PSA, conservative transmission limits were placed on paths between the 26 PSA load groupings (bubbles) and were observed when calculating the transfers between these bubbles. The aggregation of PSA load bubbles into LTRA reporting subregions may obscure differences in adequacy or deliverability between bubbles internal to a subregion.

In order to translate the preliminary analyses completed to date for the 2008 PSA, the various area bubbles used in the PSA were combined into the appropriate WECC subregions (see diagram on the previous page) 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.

In WECC's preliminary analysis for the 2008 PSA report, summer transfer capability limitations between the northern and southern portions of the Western Interconnection could occur as early as 2010 when using Planned generation. These transfer capability limitations could leave generation that is available in the northern portion unavailable to meet short-term loads in the southern region. *(Note: due to energy constraints on the operation of the hydro system in the Northwest, much of this surplus generation would be unavailable to meet multi-hour load requirements in areas external to the northern portions of the Western Interconnection).* Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report establishes that WECC presently has insufficient transmission to fully use seasonal capacity/demand diversity within the Western Interconnection.

The following table presents an example of the July imports and exports for the Arizona – New Mexico – So. Nevada subregion through 2014.

EXISTING AND EXPECTED SUMMER TRANSFERS

	Arizona - New Mexico - So. Nevada Subregion	2008	2009	2010	2011	2012	2013	2014
IMPORTS	Joint Plant Transfer to AZ-NM-SNV from RMPA	389	389	389	389	390	389	389
	Firm Purchase by AZ-NM-SNV from NWUS	480	480	480	480	480	480	480
	Joint Plant Transfer to AZ-NM-SNV from NWUS	0	0	0	0	203	229	229
	Firm Purchase by AZ-NM-SNV from SPP (external Region)	283	283	150	0	0	0	0
	Firm Purchase Contracts	763	763	630	480	480	480	480
	Firm Plant Contingent Imports	389	389	389	389	593	618	618
	Existing Imports (Firm & JP) to this subregion	**1152**	**1152**	**1019**	**869**	**1073**	**1098**	**1098**
	Future Expected Imports (including diversity exchanges)	**1173**	**1286**	**968**	**354**	**0**	**75**	**5**
	Total Existing and Expected Imports	**2325**	**2438**	**1987**	**1223**	**1073**	**1173**	**1103**
EXPORTS	Joint Plant Transfer from AZ-NM-SNV to CMUS	4169	4188	4188	4207	4207	4207	4207
	Firm Sale From AZ-NM-SNV to RMPA	300	235	235	235	235	235	235
	Joint Plant Transfer from AZ-NM-SNV to RMPA	254	254	254	254	254	254	254
	Firm Sale From AZ-NM-SNV to NWUS	221	171	171	171	171	171	171
	Joint Plant Transfer from AZ-NM-SNV to NWUS	438	438	438	438	438	449	449
	Firm Sale Contracts	521	406	406	406	406	406	406
	Firm Plant Contingent Exports	4861	4880	4880	4899	4899	4910	4910
	Existing Exports (Firm & JP) from this region to all others	**5382**	**5286**	**5286**	**5305**	**5305**	**5316**	**5316**
	Future Expected Exports (including diversity exchanges)	**236**	**254**	**258**	**251**	**298**	**249**	**249**
	Total Existing and Expected Exports	**5618**	**5540**	**5544**	**5556**	**5603**	**5565**	**5565**

In summary, inter-subregion transmission interconnection power transfer capabilities are not sufficient to accommodate all economy 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, transmission with subregions is not always sufficient to accommodate all economy energy transactions at all times of the year. WECC establishes seasonal operating transfer capability limits and invokes schedule curtailments to address the near-term inter and intra-subregion transmission limitations.

Generally, Western entities rely heavily on shorter-term power markets, for which no forecasts are available, which is a primary reason the WECC analysis uses the simulation process described above to determine the expected transfer values. The WSPP contract, which contains liquidated damage (LD) provisions, is heavily relied upon as the template for such transactions. For example, currently SMUD considers that LDs include WSPP Schedule C – type block energy contracts, which are not referenced back to specific generating units or a system of units, and for which LDs are the only remedy for non-delivery. BPA considers that all WSPP Schedule C firm power purchases and long term power purchases contain liquidated damage (make whole) provisions. Most of the entities have some contracts that are WSPP Schedule C and are not tied back to a unit(s). One entity has a contract with a wind project with a maximum capacity of 104 MW and only 66 MW of firm network transmission. The remainder of the project is imported using secondary network or non-firm point-to-point transmission.

Fuel

WECC has not implemented a formal fuel supply interruption analysis method. 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 post-2010. Gas-fired plants were historically located near major load centers and relied on relatively abundant western gas supplies. As demand for natural gas has increased dramatically for electric generation and other end-uses, (and western supplies are made available to the eastern markets) states such as California are faced with possible declining western supply availability or greater price volatility. 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 plants, increasing 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, from 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 of 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 pipeline delivery system and firm supply contracts. Introduction of LNG supplies to the Western Interchange (WI) supply mix later this decade will add a new set of fuel supply complexities.

As of 12/31/2007, the WECC's existing resource mix percentage of coal or gas/dual fuel resources were 18.7% (36,280 MW) and 41.4% (80,564 MW) respectively of 194,836 MW. In 2017, the resource mix is projected to be 19.1% (39,315 MW) of coal and 41.7% (85,950 MW) of gas/dual fuel resources out of 206,277 MW. The following table includes existing and "planned" resources.

FUEL TYPE BREAKDOWN – WECC SUMMER PEAK RATING

(Existing as of 12/31/2007 and Planned Resources)

SUMMER		Actual	Projected									
Category	**Code**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Nuclear	CSNU	9488	9559	9559	9559	9559	9559	9559	9559	9559	9559	9559
Hydro	CSHY	56646	56628	56739	57109	58072	58079	58079	58079	58079	58079	58079
Pumped Storage	CSPS	4681	4681	4741	4761	4864	4864	4864	4864	4864	4864	4864
Geothermal	CSGE	2506	2518	2518	2710	2744	2769	2769	2769	2769	2769	2769
Wind	CSWD	1167	1278	1532	1559	1598	1598	1598	1598	1598	1598	1598
Coal	CSSTC	36280	36522	36551	37792	38508	38589	39315	39315	39315	39315	39315
Oil	CSSTO	0	0	0	0	0	0	0	0	0	0	0
Gas	CSSTG	2302	2220	2220	2009	2009	2009	2009	2009	2009	2009	2009
Dual Fuel	CSSTDF	17715	17715	17715	17715	17715	17715	17715	17715	17715	17715	17715
Steam		**56297**	**56457**	**56486**	**57516**	**58232**	**58313**	**59039**	**59039**	**59039**	**59039**	**59039**
Oil	CSCTO	694	694	694	694	694	676	676	676	676	676	676
Gas	CSCTG	10353	11463	12388	12554	13038	12932	12936	12936	12936	12932	12932
Dual Fuel	CSCTDF	5138	5138	5138	5138	5138	5138	5138	5138	5138	5138	5138
Combustion Turbine		**16185**	**17295**	**18220**	**18386**	**18870**	**18746**	**18750**	**18750**	**18750**	**18746**	**18746**
Oil	CSCCO	0	0	0	0	0	0	0	0	0	0	0
Gas	CSCCG	41123	43002	44179	44223	44223	44223	44223	44223	44223	44223	44223
Dual Fuel	CSCCDF	3933	3933	3933	3933	3933	3933	3933	3933	3933	3933	3933
Combined Cycle		**45056**	**46935**	**48112**	**48156**	**48156**	**48156**	**48156**	**48156**	**48156**	**48156**	**48156**
Other	CSOT	2810	2981	3120	3205	3187	3467	3467	3467	3467	3467	3467
Undetermined/Unknown	CSUN	0	0	0	0	0	0	0	0	0	0	0
Total	**CSTF**	**194836**	**198332**	**201027**	**202961**	**205282**	**205551**	**206281**	**206281**	**206281**	**206277**	**206277**

Transmission

For the 2008 - 2017 period, approximately 8,100 miles of 230 – 500 kV transmission line projects have been reported to WECC. These projects are what the transmission planners and entities have reported to WECC for inclusion in WECC's Significant Additions report and they did not include the details as to what projects have obtained financing or site approvals.

EXISTING AND FUTURE TRANSMISSION

(CIRCUIT MILES)

	AC Voltage (kV)				+/- DC Voltage (kV)			AC & DC
Category	**230**	**345**	**500**	**Total AC**	**250-300**	**500**	**Total DC**	**Total**
Existing as of 12/31/2007	42,839	9,987	16,170	**68,996**	106	1,333	**1,439**	**70,435**
Planned First Five Years	2,428	434	2,896	**5,758**	-	488	**488**	**6,246**
Planned Second Five Years	171	701	974	**1,846**	-	-	**-**	**1,846**
Total 12/31/2017	**45,438**	**11,122**	**20,040**	**76,600**	**106**	**1,821**	**1,927**	**78,527**

WECC currently does not have a formal definition of generation deliverability, but transmission facilities are planned in accordance with NERC and WECC planning standards. These standards establish performance levels intended to limit the adverse effects of each transmission system's operation on others and they recommend that each system provide sufficient transmission 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.

Planning Authorities and the Transmission Planners are responsible for ensuring that their areas are compliant with the TPL Standards 001 through 004. When the Planning Authorities and the Transmission Planners have created their datasets and successfully run their simulations, they forward their data to the WECC (the Regional Entity). WECC's System Review Working Group (SRWG) compiles and develops a WECC-wide base case under TPL-005-0 which is used for the WECC Annual Study Program.

The Annual Study Program[181] provides base cases for WECC members and WECC staff, and provides an ongoing reliability and risk assessment of the existing and planned western interconnected electric system for the next ten years. To achieve this goal in 2007, eleven new power flow base cases were compiled and forty-one disturbances were simulated. Five of the power flow cases were prepared for conducting operating studies and the remaining six modeled various planning cases out to year 2017. 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 deficiencies leading to unacceptable system performance.

The Annual Study Program rotates its focus on specific areas of subregions. For the 2007 Study Report, the Idaho-Montana-Utah-Wyoming area 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 and long-term planning studies and to identify potential concerns requiring further investigation. For the 2008 Study Report, the Colorado-Utah-Northern Nevada-Northern California area will be the focus.

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/Dynamics Data for Transmission System Modeling & 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 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

[181] http://www.wecc.biz/TechStudies/2007StudyProgram/body07_final.pdf

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 are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. 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.

While WECC has eight back-to-back direct current ties to the Eastern Interconnection with a combined transfer capability of almost 1,500 MW, only about 614 MW of imports are planned for the 2008 summer period and there are 147 MW of exports for a net of 467 net imports. It has been reported that the capacity imports have firm resource and associated firm transmission commitments. By 2017, the imports are decreased to 301 MW and there are 182 MW of exports.

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[182]. 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.

For this LTRA and the PSA, the LRS and WECC staff used future generation information provided by the balancing authorities. The LRS and WECC staff assumes that the balancing authorities are, or will be studying the effects of these resources in the process of granting interconnection agreements.

The U.S. Department of Energy (DOE) announced the issuance of two draft National Interest Electric Transmission Corridor (National Corridor) designations in early 2007. One of two proposed National Corridors is in the Southwest area of WECC and is called the Southwest Area National Corridor which includes counties in California and Arizona. WECC's Transmission Expansion Planning Policy Committee (TEPPC) has commented to the DOE that "TEPPC is not advocating for or against the draft corridors". The Energy Policy Act of 2005 authorizes the DOE, based on the findings of DOE's National Electric Transmission Congestion Study (Congestion Study), to designate National Corridors. The DOE issues draft National Corridors in order to encourage a full consideration of all options available to meet local, regional and

[182] http://www.wecc.biz/documents/library/publications/PCC/PCC_Handbook_Section_III.pdf.

national electric demand, which includes more local generation, transmission capacity, demand response, and energy efficiency measures.

In addition to the currently planned transmission projects, there have been several mega-transmission projects proposed. Some of these are the Northern Lights – Celilo Project (Alberta to Oregon), the Northern Lights – Inland Project (from as far north as Montana to as far south as Los Angeles and Phoenix), the Frontier Line (from Montana and Wyoming to California), the TransWest Express Project (from Wyoming to Arizona), the Canada/Pacific Northwest to Northern California Study, and several others. These projects range from 1,500 to 3,000 MW of transfer capability. These projects and others are in the early stages of being considered 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 would help reduce future North-South transmission constraints such as the North-South split.

Operational Issues

Under WECC's current regional reliability plan, two reliability centers are being 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.

WECC operations personnel have the West-wide System Model, which is an energy management system (EMS) system that allows the monitoring of the electrical grid but does not allow any control. In January 2009 the reliability centers are planning to have a better monitoring system and modeling system (providing contingency analysis).

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

Most of WECC's entities are members of various reserve sharing groups that may be called upon to provide emergency imports or reserve sharing and may be outside of their respective areas. Some entities also have direct reserve sharing agreements with other entities and may be tied to a qualifying unit trip condition and may have other conditions in regards 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, systems within the Western Interconnection may seasonally exchange very significant amounts of electric power but transmission constraints between the subregions are a significant factor affecting economic use of surplus power. Due to the inter-subregion transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

The integration of variable capacity resources (wind, solar etc.) that may be required to meet state or local Renewable Portfolio Standards (RPS) raises operating issues. Integrating the generation from these variable resources into the various systems may require balancing authorities to change how they operate their system due to the intermittency and diversity, or lack thereof, of the generation from these resources. These variable resources place an increased demand on the ability of entities to regulate generation, balance their systems and support the various types of generation to meet their RPS obligations. This may require an increase in spinning reserves, or other methods to mitigate undesirable impacts on the system and to maintain reliability.

With the major additions (generation and transmission) that are planned, or the possible upgrades to existing facilities (new emission controls or other extended major maintenance items) that will need to occur over the next ten years, it may require a different pattern of maintenance outages 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.

In some areas with hydro generation, the Endangered Species Act (ESA) requirements for fish have placed more limitations on the hydro-system and operating requirements are stricter than in the past. The ability to react quickly to difficult operational circumstances has been degraded.

Other Items

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 remand 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 a significant number of thermal generating units that use once-through-cooling technology, utilizing large amounts of ocean or estuarial water. The California State Water Resources Control Board (SWRCB) is also considering a proposal[183] 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.

Considering the SWRCB proposal from the perspective of the interconnected electrical grid in California, there are reliability and market implications in the California ISO control area of removing these units from service, even assuming different levels of offsetting generation additions. It is not expected that the SWRCB will take any action until the later part of 2008. Depending on the policy adopted, impacts could be seen as soon as 2009.

Reliability Assessment Analysis

WECC does not currently have any region wide formal planning reserve margin standard. But in the past, WECC has required balancing authorities to maintain a reserve margin to cover the

[183] http://www.waterboards.ca.gov/npdes/cwa316.html

worst single planning contingency during the forecast peak hour. But as mentioned earlier, for WECC's annual Power Supply Assessment (PSA)[184] the summer and winter reserve margin targets were developed using a building block method that takes into account factors for weather, forced outages, operating reserves and operating contingencies. These planning reserve margins were held constant for the entire study period. The intent of the assessment is to identify subregions within the Western Interconnection that have the potential for electricity supply deficits below reserve targets based on reported total demand, resource, and transmission data.

While classifying the reported future resources into WECC's classes 1 through 5, any reported retirements that were associated with future resources were also studied. They were placed into the appropriate class based upon the information received and included in the assessment data and in the results. For the PSA and LTRA, conservative transmission limits were placed on paths between load bubbles and were observed when calculating the transfers between bubbles. But beyond that i.e., within the load bubbles, deliverability was not studied. Moreover, the aggregation of load bubbles into reporting sub-areas may obscure differences in adequacy or deliverability between bubbles internal to the sub-area.

Currently WECC does not use a probabilistic model that calculates the Loss of Load Probability (LOLP) or unserved energy, but WECC has a goal to investigate using a probabilistic model.

Each of WECC's transmission authorities or transmission planners performs reliability studies on its own system and compares the study results to NERC and/or WECC standards. As mentioned earlier in the transmission section, WECC staff and the System Review Working Group help develop various base cases and studies as reported in the Annual Study Report. As part of the studies, WECC staff does perform selective transient dynamics and post-transient analyses on the base cases and has these published in WECC's Annual Study Report.

WECC currently has Power System Stabilizer (PSS) standards that require generators with high initial response exciters to be equipped with a PSS and to have those PSS properly tuned and in-service. The Power System stabilizer (PSS) is an optional control that is part of the excitation system for generator control. The PSS acts to modulate the generator field voltage to damp electrical power-speed oscillations. Due to these standards, the Western Interchange does not regularly perform WECC-wide small signal stability studies but has conducted them in the past and used them for technical justification of the PSS standard.

As part of WECC's Planning Coordination Committee Handbook, WECC has developed a WECC a Disturbance – Performance Criteria and a Voltage Support and Reactive Power Standard, these can be found on pages XI 16-17[185] and pages XI 36-39. The WECC Disturbance – Performance criteria provides standards for Transient Voltage Dip, Minimum Transient Frequency and Post Transient Voltage Deviation.

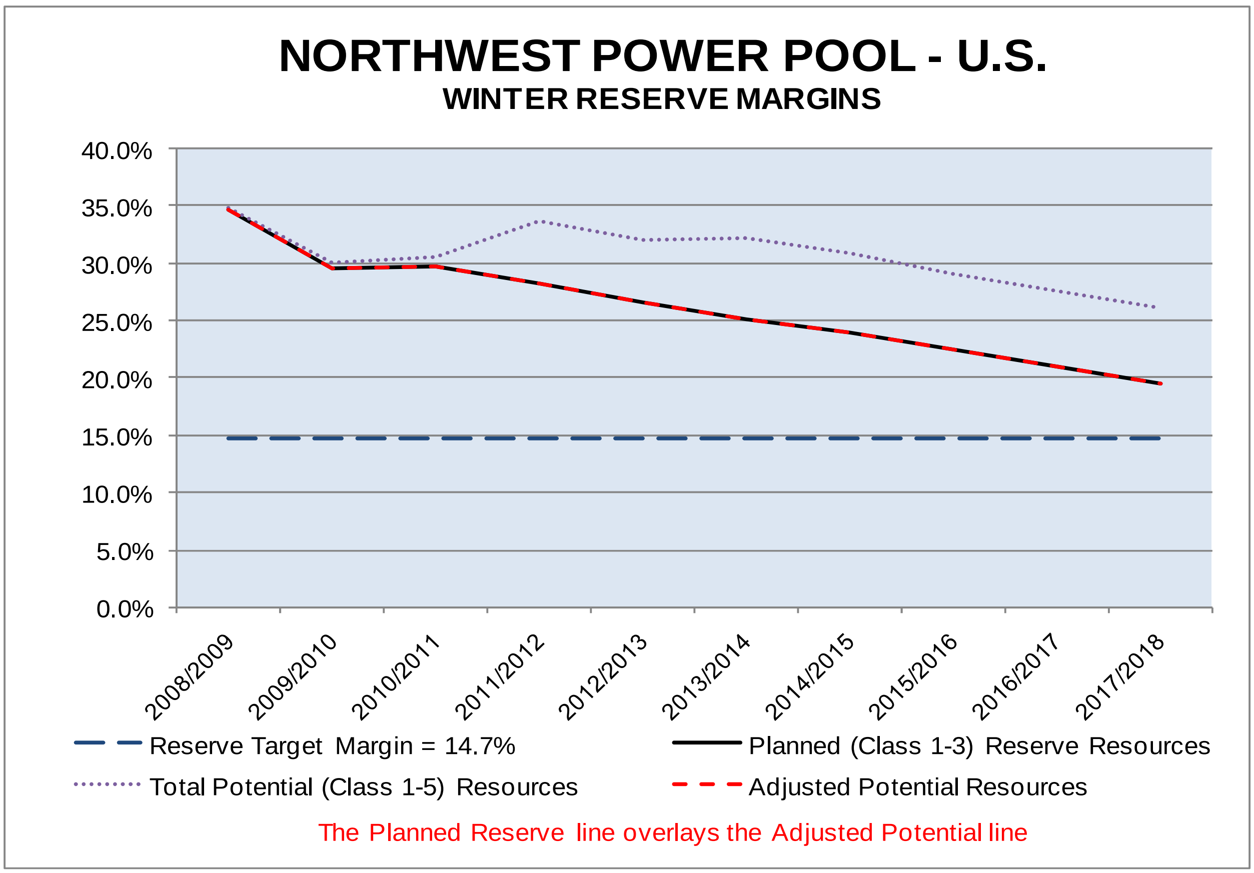
The Voltage Support and Reactive Power Standard help provide the criteria for minimum dynamic reactive requirements. Dynamic reactive power support and voltage control are

[184] Link to WECC's Power Supply Assessment Reports
[185] http://www.wecc.biz/documents/library/publications/PCC/PCC_Handbook_Section_11.pdf

essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources. Reactive power sources must be distributed throughout the electric systems among the generation, transmission, and distribution facilities, as well as at some customer locations. Because customer reactive demands and facility loadings are constantly changing, coordination of distribution and transmission reactive power is required. Unlike active or real power (MW), reactive power (Mvars) cannot be transmitted over long distances and must be supplied locally. Each year WECC sends out a data request letter to the Technical Studies Subcommittee (TSS) and the System Review Working Group asking for areas of "potential voltage stability problems and the measurers that are being taken to address the problems throughout the WECC region." The results of this survey are compiled and posted on the WECC website as the Voltage Stability Summary. The Voltage Stability Summaries, by year are available on the WECC website[186].

Subregions

Northwest Power Pool Area

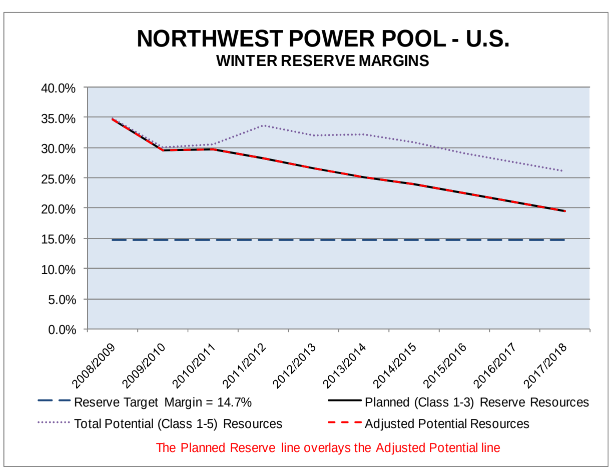


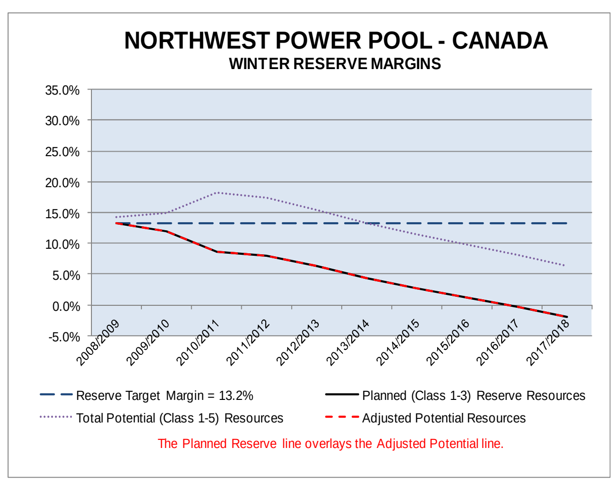
[186] Link to WECC Voltage Stability Summaries

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 2008 through 2017, winter total internal demands are projected to grow at annual compound rates of 1.4 percent and 2.4 percent in the United States and Canadian areas, respectively. For the total NWPP, the difference in the summer of 2017 between the net capacity resources (77,071 MW) and the total internal demand plus target margin (76,169 MW) and is 902 MW or 4,937 MW without future expected sales. The difference in the winter season of 2017-2018 (82,931 MW – 83,892 MW) is -961 MW or -4,224 MW without future expected purchases. For the assessment period 2008 through 2017, the annual energy requirements are projected to grow at annual compound rates of 1.65 percent and 2.68 percent in the U.S. and Canadian areas, respectively.

The annual energy use for the NWPP, increased by 2.5 percent from 368,894 GWh in 2006 to 378,304 GWh in 2007. The 2007 energy use was 1.8 percent greater than the forecast in last year's assessment. Annual energy use for the ten-year period from 2007 through 2017 is forecast to increase by 1.9 percent compared to the historic annual energy use increase of 1.3 percent from 1997 through 2007. For the period from 2007 through 2017 the annual energy requirements are projected to grow at annual compound rates of 1.5 percent and 2.8 percent in the U.S. and Canada areas, respectively.

Resource Adequacy Assessment — The winter Planning Reserve Margin for the United States portion of the NWPP (NWPP-US) is 14.7 percent. The data indicates a winter 2008/2009 reserve margins of 31.8 percent without any "Planned" generation or expected sales and 34.7 percent with those resources (Reported Margin). Much of WECC's forecast surplus reserve margin exists due to the Columbia River Basin hydroelectric dams located in the NWPP-US, but deliverability to other areas is problematic due to both the possibility of a constrained North-to-South transfer capability and the limited energy associated with the hydro storage. By winter 2012/2013, those margins change to 23.7 percent and 26.7 percent, respectively. *(Note, due to energy constraints on the operation of the hydro system in the Northwest, much of this surplus would be unavailable to meet multi-hour load requirements, including transfers to other regions of WECC).*





For the Canadian portion of the NWPP, the winter planning reserve margin is 13.2%. In the winter of 2008/2009, the reserve margins are 7.3 percent without any "planned" generation or expected purchases and 13.2 percent with those resources. In WECC's 2008 PSA, the Alberta 150 MW interconnection with the Saskatchewan was not modeled. There are several short lead time generation technologies that responded to market conditions in the provinces, that may not have been in the regulatory permitting phase (for example wind and simple cycle gas turbines) and were classified as being class 4 or 5. Consequently, the assignment of a zero percent confidence factor to the "proposed" (Class 4 and 5) resources has a significant impact on the reserve margin of the Canada sub-region. The first year that the subregion goes below the reserve target margin with "planned" resources and expected transactions is projected to be the winter of 2009-10. That winter the reserve margin would be 11.9% or the difference between net capacity resources (24,992 MW) and the total internal load plus reserve margin (25,293 MW) is a negative 301 MW. As mentioned previously, there are some resources in the proposed category that fall under the short-lead time technologies and have an in-service date prior to the winter of 2009, which would delay the time when the Canada sub-region would drop below the target margin. The next year, the subregion is projected to be deficient by -1,054 MW. By the winter of 2012/2013, those margins decline to a negative 3.3 percent without any "planned" generation or expected purchases and 6.3 percent with those resources (25,622 MW – 27,295 MW = -1,673 MW below target). The Canadian entities are aware of the need for resource adequacy and transmission reinforcement and believe that through the open market and proper planning the resource adequacies will be met.

The AESO has instituted "The Two Year Probability of Supply Adequacy Shortfall Metric" [187]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 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.

Generation in the province of Alberta, Canada, operates in a fully deregulated market and thus resource additions are market driven. 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 the transmission systems outside of Alberta.

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) coordinates 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

[187] http://www.aeso.ca/downloads/LTA_Recommendations_Paper_Final.pdf pages 18-24 Items 4 through 5.5

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; navigation; and refilling of the reservoirs. With the recent addition of significant wind resources, these hydro electric resources are also used to integrate wind into grid operations. 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. However, this agreement is subject to three-, five-, and eight-year performance checks and reopening by the parties. 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 & 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 very significant. Much of the coal fired generation is near the fuel sources and is often 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 more often operated as seasonal peaking units. Wind-powered generation is increasing rapidly in the area. As of 12/31/07, the existing wind resources within WECC, the NWPP has 47.9 % of WECC's non-derated wind resources (3,243 MW), and 51% of the expected summer on-peak wind capacity (539 MW.) Of the future WECC planned and projected wind resources, the NWPP accounts for 1,566 MW (61%) and 7,504 MW (95%) respectively. The expected derated summer on-peak values are 247 MW for the planned resources and 314 MW for the projected resources but the "adjusted" projected value is 0 MW. Since the wind resources exhibit wide fluctuations in output, areas with relatively large amounts of wind-powered generation are investigating the costs and options for integrating wind. Careful and site-specific assessments are needed to minimize adverse consequences that may occur.

***Transmission Assessment* —** In view 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 allowing 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 2,285 miles of 500-kV transmission lines (1,882 miles NWPP-US and 403 miles NWPP-CN).

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission grid operation. 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.

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 (adding reactive sources) or new facilities (a new transformer) have been proposed as items to be budgeted and installed. Because some of these are driven by future load growth and transmission 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 at this time.

Some balancing authorities are taking steps to help make the transmission queue process and transmission queue assessments are more efficient. BPA has instituted a process called the Network Open Season[188] (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. For more information refer to the link below.

In Alberta, several system reinforcement projects have been completed recently. The most significant of these is the re-energization of the Keephills – Genesee and Genesee – Ellerslie 240 kV lines to their design voltage of 500 kV. This also included the addition of 500/240 kV transformers at the Keephills and Ellerslie substations. A project to reinforce the downtown area of Edmonton with the addition of 6 miles of underground 240 kV cable is nearing completion and has a late fall 2008 in-service date.

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 an in-service date of 2009. Need approval has also

[188] http://www.bpa.gov/corporate/pubs/fact_sheets/08fs/fs_Network_Open_Season.pdf

been received for a number of projects in the Edmonton area. These projects will also include the installation of two 600 MVA 240 kV phase shifting transformers (the first in Alberta) to be used to balance the flows between the northwest and the northeast regions of the province.

Planning efforts continue on a number of other major system reinforcements including supply into the Fort Saskatchewan and For 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 greed in Alberta. For various regions 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.

A Calgary area transmission must run (TMR) procedure addresses 240-kV transmission grid-loading issues and ensures that 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.

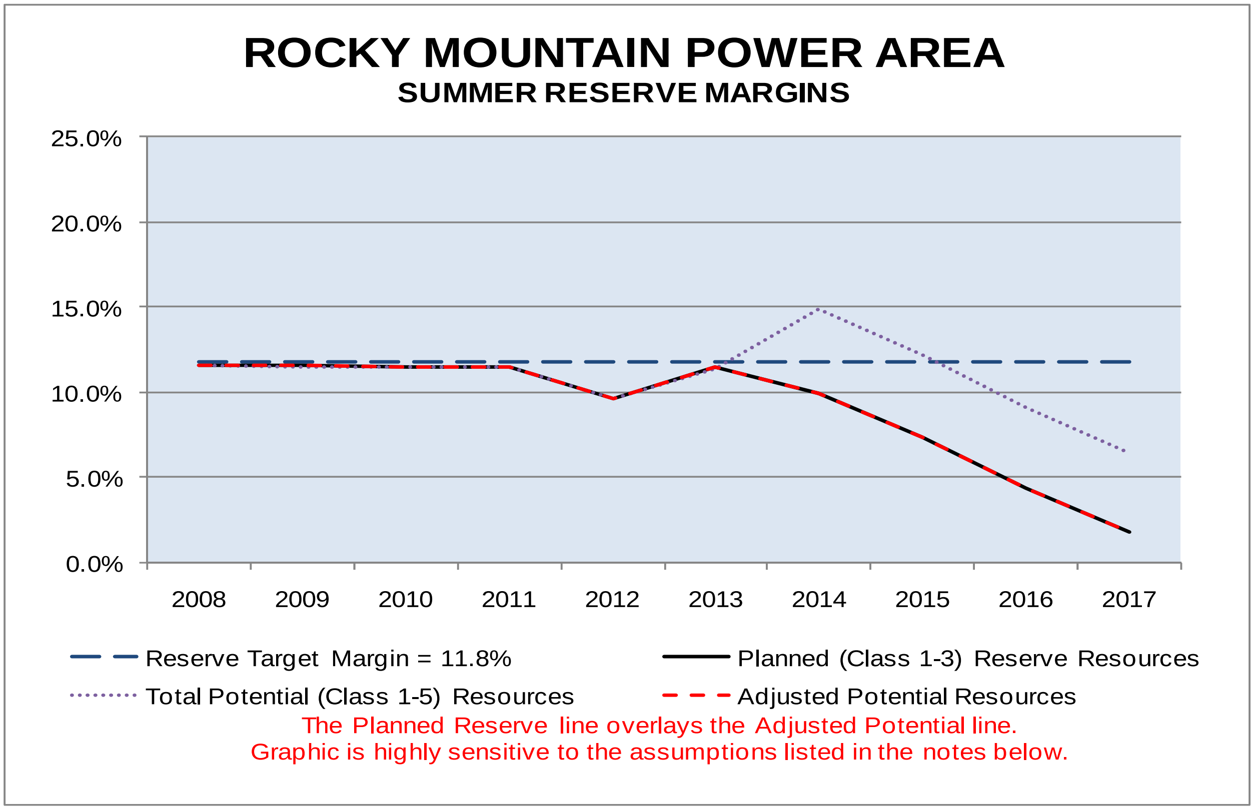
The Canadian province of British Columbia relies on hydroelectric generation for 90 percent of its resources. British Columbia Transmission Corporation (BCTC) is responsible for the planning, operation, and maintenance of British Columbia's publicly-owned transmission system. BCTC is addressing constraints between remote hydro plants and lower mainland and Vancouver Island load centers. The Interior to Lower Mainland[189] (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 and has a projected in-service date in 2014. The Vancouver Island Transmission Reinforcement[190] project involves 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. The expected in-service date of the project is October 2008. The ILM reinforcement project will increase the total transfer capability of the interior to lower mainland area grid and the new 230-kV cable will increase the transfer capability from the lower mainland area to Vancouver Island.

Operational Issues — Under normal weather conditions, the NWPP does not anticipate dependence on imports from external areas during summer peak demand periods. In the event of either extreme weather or much lower than normal precipitation, the NWPP could increase imports, which would reduce reservoir drafts and aid reservoir filling. Off-peak energy transfers allow southwest generators to increase thermal plant loading during normally light load hours to offset to some extent the effects of any adverse hydro conditions.

Preliminary analysis for WECC's 2008 PSA report indicates that transmission constraints exist between the United States and Canadian portions of the NWPP and that by 2017 over 4,000 MW of additional capacity (generation or transmission for imports) will be needed in Canada. The majority of this additional capacity will need to come from IPPs or the market.

[189] http://www.bctc.com/projects/ilm/
[190] http://www.bctc.com/projects/vitr/

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 due to variations in weather. For the period from 2008 through 2017, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.35 percent and 2.24 percent, respectively. The difference in 2017 between the “Planned” reserve resources (15,418 MW) and the total internal demand plus target margin (16,880 MW) and is -1,462 MW (this includes serving 398 MW of interruptible load).

Annual energy use increased by 3.1 percent from 61,174 GWh in 2006 to 63,050 GWh in 2007. The 2007 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 2007 through 2017 is forecast to increase by 2.4 percent compared to the historic annual energy use increase of 3.0 percent from 1997 through 2007. Annual energy use for the nine-year period from 2008 through 2017 is forecast to increase by 2.2 percent.

Resources — The RMPA target margin is 11.8 percent for the summer and 13.4 percent for the winter. The data for the Rocky Mountain Power Area present the summer 2008 reserve margins of 9.4 percent without any “Planned” generation or expected purchases and 11.5 percent with those resources (including serving interruptible load) (“Planned” reserve margin). The first time the reserve margin goes below the target margin with the “Planned” resources and expected purchases is in July of 2012, where there is a shortfall of 245 MW which produces a margin 9.6%.

As of 12/31/2007, of the existing summer rated wind resources within WECC, the RMPA has 662 MW (10% of the WECC nameplate) which is derated to 80 MW during the summer peak period (7% of the WECC on peak wind capacity). Of the future WECC planned and projected non-derated wind resources, the RMPA accounts for 449 MW (17%) and 0 MW (0%) respectively. The expected derated summer on-peak value is 56 MW for the planned resources.

Public Service Company of Colorado (PSC) has a 750 MW coal-fired plant under construction at the existing Comanche station with an expected in-service date of 2010. There is also the Holcomb 1 coal fired generator (700 MW) planned for 2013. Holcomb 2 is projected for 2014, but had the confidence factor applied to it, so it is only reflected in the potential line on the reserve graph. (As mentioned in the highlights section, it is questionable as to whether either of these Holcomb units will meet their current in-service dates.)

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.

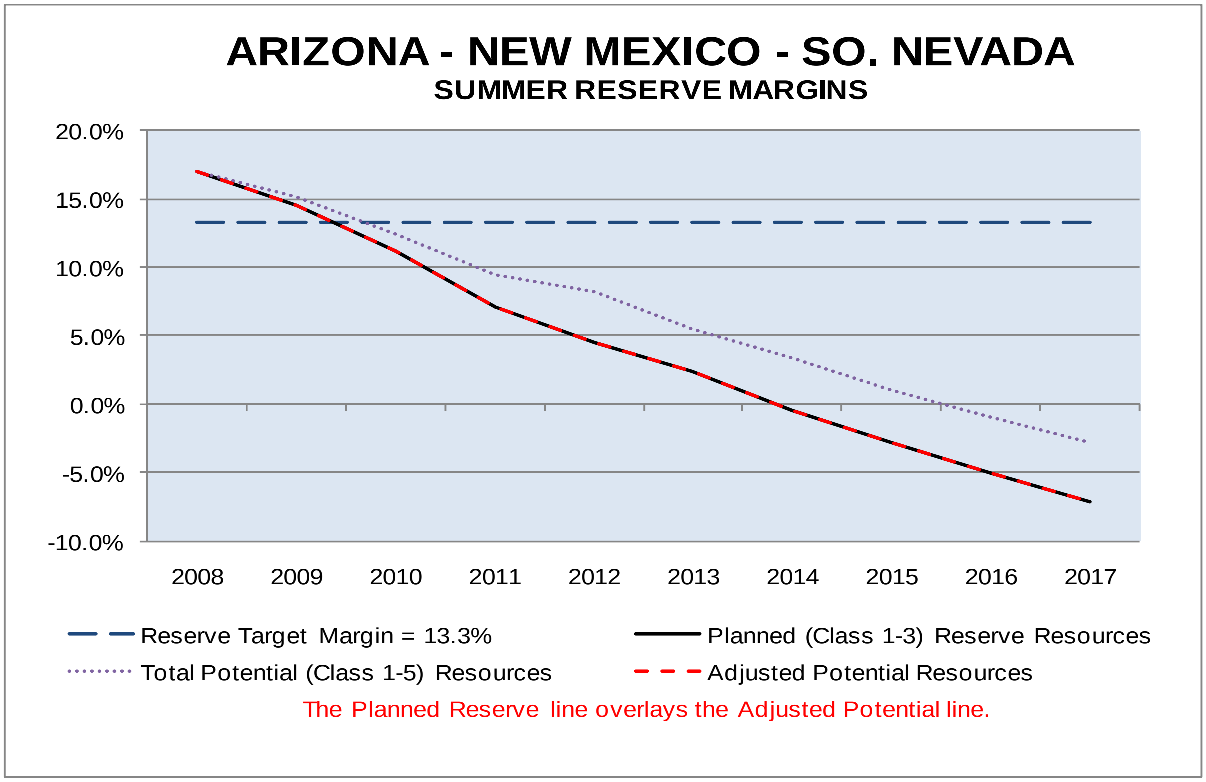
***Fuel Supply and Delivery* —** Coal, hydro, and gas-fired plants are the dominant electricity sources in the area. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants, however, may experience operational limitations due to 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 new project in southern Colorado called the San Luis Valley Electric System Improvement project. The project would involve the construction of a 80 mile 230-kilovolt 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 that 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 megawatts. 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.

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.

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 2008 through 2017, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.7 percent and 2.5 percent, respectively. The difference in 2017 between the "Planned" reserve resources (37,332 MW) and the total internal demand plus target margin (45,438 MW) and is -8,106 MW (this includes serving 575 MW of interruptible load and 187 MW of direct control load management.)

The AZ-NM-SNV reserve margin graph depicts that the subregion drops below its reserve target margin as early as 2010 due to lack of resources both within the subregion and from surrounding subregions. The SAM model used for the LTRA and PSA allows the transfer of excess energy to areas of need or higher cost, based upon transfer costs and whether the target margin was met. Since California is closer to the Northwest, the cost of transmission is less and much of the excess generation in the northwest is absorbed into California and then if any is left after it continues to the RMPA or AZ-NM-SNV subregion. The north-south split occurs in 2010 where there is not adequate transmission to allow the transfer of energy through California and into the AZ-NM-SNV subregion in 2010. .

The annual energy use increased by 5.9 percent from 134,950 GWh in 2006 to 142,951 GWh in 2007. The 2007 energy use was 4.7 percent greater than the forecast in last year's assessment. For the ten-year period from 2007 through 2017, the energy use is forecasted to increase by 2.2 percent compared to the historic annual energy use increase of 3.8 percent from 1997 through 2007. The annual energy use from 2008 through 2017 is forecast to increase by 2.5 percent.

Resource Adequacy Assessment— The AZ-NM-SNV planning reserve margin target is 13.27 percent for the summer and 12.77 percent for the winter. The data for this sub-area present the summer 2008 reserve margins of 11.4 percent without any "Planned" generation no expected purchases and 17.0 percent with those resources (Reported Margin). With or without the "Planned" generation and expected purchases, the AZ-NM-SNV falls below the planning reserve target in July 2010 where it drops to 4.2 percent without the resources, and only drops to 11.1 percent with the resources (this includes serving DSM loads). By the summer of 2012, those margins further decline to a negative 1.3 percent and a positive 4.5 percent, respectively, as depicted in the margin information graphic.

Long-term contracts have been signed since the data for the PSA and LTRA were submitted and thus are not included in the current analysis. SRP signed a twenty year contract for 500 MW of peaking capacity with TransCanada beginning in 2011. The plant will be built 45 miles southeast of Phoenix.

Of the existing wind resources within WECC, the AZ-NM-SNV has 295 MW (4% of the WECC nameplate) which is derated to 1 MW during the summer peak period (0% of the WECC on peak wind capacity). Of the future WECC planned and projected wind resources, the AZ-NM-SNV has projected 0 MW.

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. The margin information graphic for the area demonstrates the subregion faces a somewhat limited window of opportunity to address area resource adequacy issues. 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 plan procedures or some other similar process.

Fuel Supply and Delivery **—** Coal, hydro, and nuclear plants are the dominant electricity sources in the area. As in the northwest, 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.

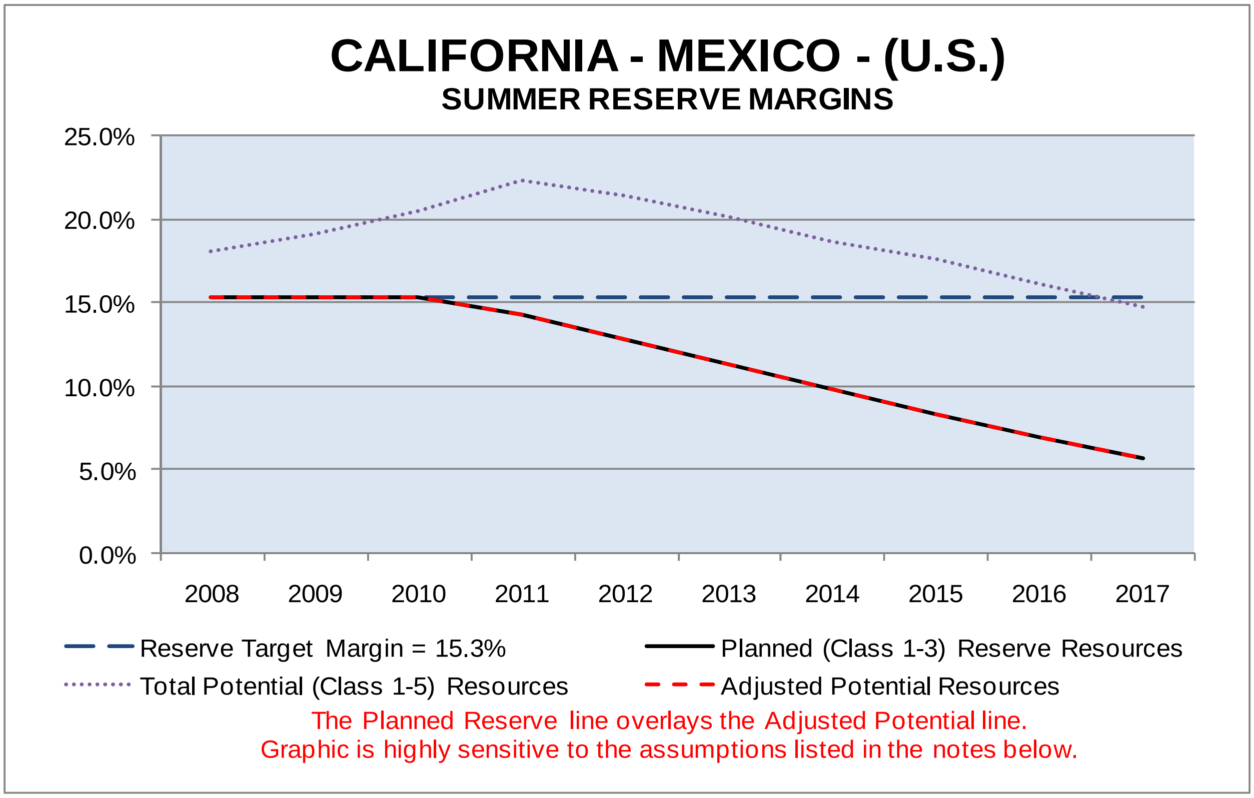
Transmission Assessment **—**Transmission providers from the AZ-NM-SNV along with other stakeholders from southern California are actively engaged in the Southwest Transmission Expansion Planning (STEP) group. The goal of this group is to participate in the planning, coordination, and implementation 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 will increase the transfer capacity by 1,245 MW and is scheduled to be completed in 2008. The third and last set of upgrades is the Palo Verde to Devers #2 500-kV transmission line (PVD2). The 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 Palo Verde to Devers #2 line which may cancel or delay the construction of the PVD2 line. Currently Southern California Edison (SCE) is projecting the in-service date of the PVD2 line to be in 2011. SCE states that after all regulatory approvals for the project the construction of the project will take approximately 2 years. This line was not included in this year's LTRA or PSA analysis, since in last year's SAM analysis, this line did not have an impact on transfers due to the AZ-NM-SNV being short on resources and there was still unutilized capacity on the existing transmission lines going from the California-Mexico subregion into the AZ-NM-SNV.

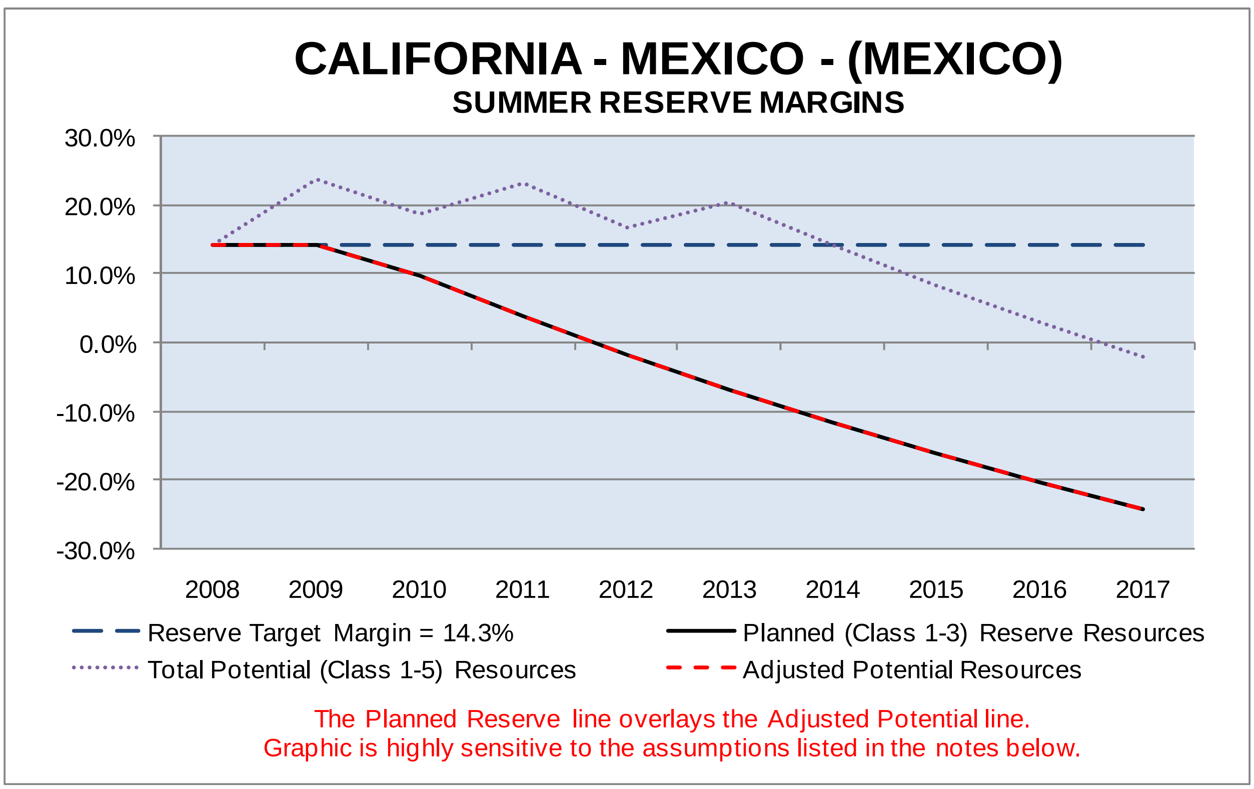
As mentioned earlier, the Department of Energy (DOE) has also studied various areas of congestion and identified the desert southwest as an area of concern and has proposed the Southwest Area National Corridor which includes counties in California and Arizona. The table at the end of the WECC self assessment outlines some of the ongoing transmission projects that are past the conceptual stage and considered in this assessment.

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 that the system can respond adequately to planned and unplanned transmission and/or generation outages.

With the numerous coal fired generators residing in this subregion, there could be significant impact from possible carbon emission limits. WECC's TEPPC group is currently studying the possible impact or alternatives to reduce the carbon emissions.

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 1.3 percent and 5.5 percent in the United States and Mexico areas, respectively, from 2008 through 2017. Annual energy requirements are projected to grow at annual compound rates of 1.3 percent and 5.2 percent in the U.S. and Mexican areas, respectively. The difference in 2017 between the "Planned" reserve resources (75,935 MW) and the total internal demand plus target margin (82,473 MW) and is a negative 6,538 MW (this includes serving 75 MW of interruptible load and 3,281 MW of direct control load management.) Of the 14,711 MW of total "proposed" resources (summer peak rating) throughout WECC,, about 6,900 MW are projected for the California-Mexico Area (but have a zero percent confidence factor assigned to them, zeroing them out.) California, which generally peaks in August, shows dropping below its planned reserve margin in August of 2011 (while serving total load and not calling upon their DSM programs). A large portion of the load management programs or interruptible load available to the California Independent System Operator (CAISO) use a Stage 1 or Stage 2 emergency as trigger mechanisms for the CAISO to access these programs. California accounts for 2,892 MW or 94.7 percent of the 3,053 MW of Direct Control Load Management (DCLM) for 2008.

The California-Mexico subregion's annual energy use increased by 1.5 percent from 297,339 GWh in 2006 to 301,736 GWh in 2007. The actual 2007 energy use was 2.1 percent less than the forecast in last year's assessment. Annual energy use for the ten-year period from 2007 through 2017 is forecasted to increase by 1.5 percent compared to the historic annual energy use increase of 1.6 percent from 1997 through 2007. Annual energy use for the nine-year period from 2008 through 2017 is forecast to increase by 1.5 percent.

Resource Adequacy Assessment — The California-Mexico total area (CA-MX) planning reserve margin is 15.3% for the summer and 11.0% for the winter. The planning reserve margin for California U.S. is 15.3% and 11.0% for the summer and winter respectively. The planning reserve margin for Baja Mexico is 14.3% and 10.3% for the summer and winter respectively. The data for the United States portion of the California-Mexico sub-area present summer 2008 reserve margins of 7.2 percent without any "planned" generation or expected purchases and 15.3 percent with those resources. Using "planned" resources and expected purchases, California first shows going below its planned reserve margin in August of 2011, where there is a shortfall of 615 MW which produces a margin 14.3%. In the summer of 2012, California's reserve margin is 12.7 percent as depicted in the margin information graphic. For the Mexican portion of the subregion, the summer of 2008 reserve margins are 25.5 percent without any "planned" generation or expected sales and 14.3 percent with those resources. By the summer 2012, those margins become a negative 14.9 percent and a negative 1.7 percent, respectively.

Of the existing wind resources within WECC,(6,574 MW of nameplate and derated to 1,167 MW on-peak) the CMUS has 2,374 MW (36% of the WECC nameplate) which is derated to 490 MW during the summer peak period (42% of the WECC on-peak wind capacity). Of the future WECC planned and projected wind resources, the CMUS accounts for 566 MW (22%) and 406 MW (5%) respectively. The expected derated summer on-peak value is 125 MW for the planned resources, 121 MW the projected resources but the "adjusted" projected value is 0 MW.

The shortfall in Mexico in 2017, between the total load plus planned margin (4,111 MW) versus the planned resource reserve (2,722) is -1,389 MW

California employs a mandatory resource adequacy program requiring load serving entities to procure 115% of their forecast demand. State entities are working together and with other entities in the Western Interconnection to address transmission planning issues.

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 5th, 2007 California adopted *the 2007 Integrated Energy Policy Report (IEPR)*[191] 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"

***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)*[192] and on page 16 begins to address the Natural Gas Supply, Demand and Infrastructure and states they will: A) Continue to monitor and assess the gas market and its impact on California consumers; B) Examine whether and how California utilities should enter into contracts for LNG supplies; C) Ensure that California has adequate access to those supplies. The UEAP also mentions that there have been proposals for 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)[193] 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 siting permitting.

As mentioned earlier, With the Arizona Corporation Commission's May 2007 denial of SCE's Palo Verde – Devers #2 (PVD2) permit, Southern California Edison delayed the projected in-service date to be in 2011. On May 16, 2008, SCE filed its pre-filing application at FERC. The FERC pre-filing process triggers a project wide National Environmental Policy Act review, preparation of a preliminary draft environmental impact statement, and noticing along the entire right-of-way. SCE is requesting the pre-filing process to conclude by end of 2008. SCE also filed a motion to modify the PVD2 with the CPUC on May 16, 2008 to support interconnection needs in the region near Blythe, California. SCE requested to construct PVD2 facilities in California to

[191] http://www.energy.ca.gov/2007_energypolicy/index.html
[192] http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF
[193] http://www.energy.ca.gov/reti/index.html

allow SCE to access potential new renewable and conventional gas fired generation in the Blythe, California area.

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 is moving forward on a Market Redesign and Technology Upgrade (MRTU) program of changes to ISO market and grid operations. The CAISO launch date for the MRTU program is now projected to be in 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 in the area have alleviated some transfer capability limitations, but numerous system constraints remain.

Regional Description

WECC's 216 members, including 35 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.

Abbreviations Used in This Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
CA-MX-US	California-México (Subregion of WECC)
dc	Direct Current
DOE	U.S. Department of Energy
EECP	Emergency Electric Curtailment Plan
ERO	Electric Reliability Organization
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool
GTA	Greater Toronto Area
GWh	Gigawatthours
ICAP	Installed Capacity
IESO	Independent Electric System Operator (in Ontario)
IROL	Interconnection Reliability Operating Limit
ICTE	Independent Coordinator of Transmission for Entergy
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent Transmission System Operator
MRO	Midwest Reliability Organization
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
ONT	Ontario – IESO
OVEC	Ohio Valley Electric Corporation
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PJM	PJM Interconnection
PRB	Powder River Basin
PRSG	Planned Reserve Sharing Group

RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RCC	Reliability Coordinating Committee
RFC	Reliability*First* Corporation
RFP	Request For Proposal
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RRS	Reliability Review Subcommittee
RTO	Regional Transmission Organization
SCR	Special Case Resources
SERC	SERC Reliability Corporation
SOL	System Operating Limit
SWPP	Southwest Power Pool
SPP	Southwest Power Pool
SPS	Special Protection System
TRE	Texas Regional Entity
THI	Temperature Humidity Index
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
VACS	VACAR – South
WECC	Western Electricity Coordinating Council

Capacity, Demand & Event Definitions

a) Demand Definitions

Total Internal Demand: Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).

Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

b) Demand Forecast Bandwidths

The Load Forecast Working Group (LFWG) is responsible for assessing uncertainty inherent in the forecasts provided by member Regions in accordance to the NERC standards for the long-term reliability assessments. For this purpose, LFWG develops uncertainty bandwidths around aggregated Regional, United States and Canadian annual forecasts of peak demand and energy.[194]
.
For a more comprehensive discussion on method, a research paper "Method Proposal for the NERC 2008-2017 Regional and National Peak Demand and Energy Projection Bandwidths,"[195]

Background - Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or *midpoint*. Each NERC's Region Member is responsible to provide demand forecasts for the long term Reliability Assessment 2008-2017. Each regional demand forecast, for example, is assumed to represent the expected *midpoint* of possible future outcomes. This means that a future year's actual demand may deviate from the midpoint projections due to variability in key factors that drive electrical use. In the case of the NERC regional forecasts, there is generally a *long-run* 50% probability that actual demand will be higher than the forecast midpoint and a *long-run* 50% probability that it will be lower.

For securing energy supply or ensuring reliability of the bulk power system, adequate risk management implies defining possible future outcomes and their probability of occurrence.

For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, LFWG develops upper and lower 10% confidence bands around the NERC regional peak demand and energy forecasts. *This means that there is a long-run 80% probability that future demand and energy will occur within these bands.* Conversely, there is a

[194] For the full report, see http://www.nerc.com/docs/pc/lfwg/NERC_2008-2017_Regional_Bandwidths.pdf
[195] http://www.nerc.com/docs/pc/lfwg/Method_for_2008-2017_Bandwidths.pdf

10% chance that future outcomes could be less than the lower band, and a 10% chance that future outcomes could be higher than the upper band.

Overview of Method - LFWG continued to introduce enhancements to the regional bandwidth method this year. The previous method used first order autoregressive models for every region's energy, summer peak, and winter peak. Although using a single statistical time-series model has merits and results were satisfactory, LFWG desired to investigate other approaches and model specifications for possible improvements or better model fits. Optimal modeling for each Region and each series (energy, summer peak, and winter peak) was identified by the LFWG members.

It leads to an automated model selection procedure based on minimizing the BIC statistic, or Schwarz Bayesian Information Criterion. [BIC = n * ln(MSE) + k * ln(n)], where MSE = (SSE/n) is the mean squared errors, n is the number of observations, and k is the number of parameters. The study looked at a variety of univariate time-series models including simple ARIMA models, the original first order autoregressive model, a first order moving average model, and random walk, with and without drift. The study also looked at a linear trend, simple exponential smoothing, and other smoothing techniques such as Holt, Holt/Winters, and damped exponential. Results indicate candidate models can be limited to the four simple ARIMA type models, since in both cases the method selected only those models (See Table A-1).

No.	Candidate Model	Form	ARIMA (p,d,q)Notation	Frequency
1	Random Walk with drift	$y_t = \mu + y_{t-1} + \varepsilon_t$	(0,1,0) with Intercept	17
2	Random Walk without drift	$y_t = y_{t-1} + \varepsilon_t$	(0,1,0) without Intercept	4
3	Moving Average	$y_t = \mu + \varepsilon_t + \theta\varepsilon_{t-1}$	(0,1,1) with Intercept	7
4	Autoregressive	$y_t = \mu + \rho y_{t-1} + \varepsilon_t$	(1,1,0) with Intercept	5

Table A-1: Models for Bandwidth Calculations

The principal features of the regional bandwidth method include:

1. The regional projections of demand and net energy for load are modeled as a function of past peak demand or energy. An optimal model is selected for each region's energy, summer peak, and winter peak (33 models in all).

2. The most frequent (17 out of 33) optimal model was the random walk model with drift specification. This approach expresses the current value of the time series as a linear function of the previous values of the series and a random shock. The functional form again is:

$$y_t = \mu + y_{t-1} + \varepsilon_t$$

   where μ is a constant term. The shocks ε_t are random errors or white noise and are assumed to be normally and independently distributed with mean zero, constant variance, and σ_ε^2 independent of y_{t-1}

3. In cases where membership changes resulted in significant changes to a region's energy and load, an intervention variable is added to the equation to allow the bandwidths to suitably depict post-change energy and load uncertainty. The historic variability observed in demand and energy is used to develop uncertainty bandwidths for demand and energy projections. Variability, represented by the variance σ_ε^2 of the historic data series, is combined with other model information to derive the uncertainty bandwidths unique to each regional projection.

Each of the eight US and three Canadian regions is modeled separately with three regions segmented into their United States and Canadian counterparts. Irregular patterns of deregulation, different economic trends, and variable weather patterns contribute to the variability of actual peak demand and electricity use. The response to these factors differs across regions due to different weather variation, economic conditions, energy prices, and regulation/deregulation policies. The bandwidths around NERC regional projections of long-term peak demand forecasts implicitly reflect the combined uncertainty from these factors. Accordingly, the bandwidth results on a region-by-region basis are unique.

Results[196]- The bandwidths produced are theoretical bandwidths based on mathematical representations of the series. They are derived from in sample residuals (fitting errors) and 80% standard normal confidence intervals. Bandwidths obtained with the theoretical formulas are then proportionally projected onto the regional forecasts provided by the Regions.

Table A-2 shows the optimal model for each region based on the BIC statistic. The graphical and numerical results of the bandwidth analyses follow in the figures and tables below:

Table & Figure	Region	Net Energy for Load	Summer Demand	Winter Demand
1	ERCOT	RW with drift	RW with drift	RW with drift
2	FRCC	RW with drift	Autoregressive	Autoregressive
3	MRO-US	RW with drift	RW without drift	Autoregressive
4	NPCC-US	RW with drift	RW without drift	RW without drift
5	RFC	RW with drift	Autoregressive	RW without drift
6	SERC	RW with drift	RW with drift	RW with drift
7	SPP	RW with drift	Autoregressive	RW with drift
8	WECC-US	Moving Average	Moving Average	Moving Average
9	MRO-Can	RW with drift	Moving Average	Moving Average
10	NPCC-Can	RW with drift	RW with drift	RW with drift
11	WECC-Can	RW with drift	Moving Average	Moving Average
12	US	Sum of regions	Sum of regions	Sum of regions
13	Canada	Sum of regions	Sum of regions	Sum of regions

Table A-2: Optimal Model for Bandwidth Calculation by Region

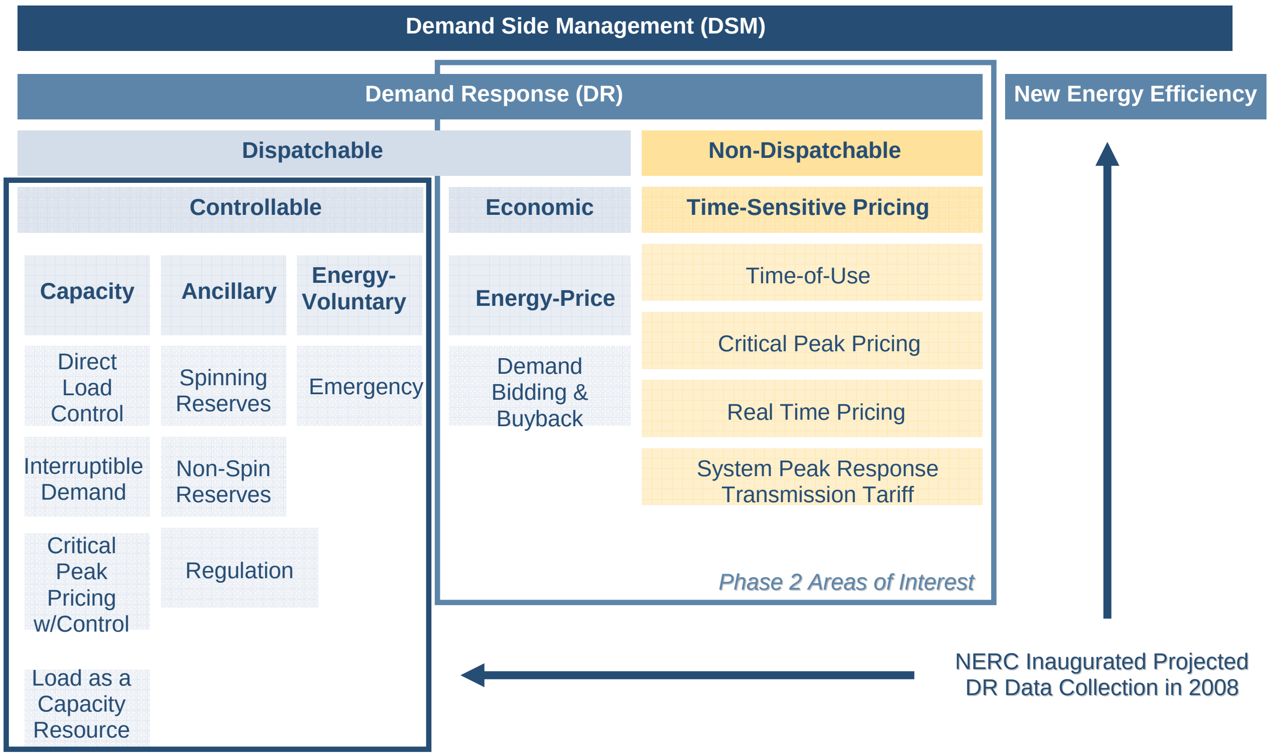
The traditional method for choosing or "identifying" the correct form of an ARIMA model is to visually examine the autocorrelation and partial autocorrelation functions of the data series. Doing this for the energy series results in the same outcome as the optimization method for all cases where the Random Walk with drift model is optimal. Where the optimization method chose an MA model for WECC-US energy, visual identification indicates a toss-up between the MA and AR models.

196 During the 1990s and 2000s several regions including MAIN, MAPP, MRO, RFC, SERC and SPP experienced changes in membership and geography. The historical net energy and peak load data and figures depict these changes.

c) Demand Response Categorization

Information about demand response categories in Phase 1 were collected for the 2008 Long Term Reliability Assessment. Figure A-1 provides an overview of NERC's Demand-side management categories.

Figure A-1: Demand-Side Management and NERC's Data Collection



Each of these elements of demand response is defined below:

Demand Response: changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized

Dispatchable: demand-side resource curtails according to instruction from a control center

Controllable: dispatchable demand response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints

Capacity: demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance

Direct Control Load Management: demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

Contractually Interruptible (Curtailable): curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Critical Peak Pricing (CPP) with Control: demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Load as a Capacity Resource: demand-side resources that commit to pre-specified load reductions when system contingencies arise

Ancillary: demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance

Non-Spin Reserves: demand-side resource not connected to the system but capable of serving demand within a specified time

Spinning/Responsive Reserves: demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

Regulation: demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin

Energy-Voluntary: demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized

Emergency: demand-side resource curtails during system and/or local capacity constraints

Non-dispatchable[197]: demand-side resource curtails according to tariff structure, not instruction from a control center

Time-Sensitive Pricing: retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods

Time-of-Use (TOU): rate and/or price structures with different unit prices for use during different blocks of time

Critical Peak Pricing (CPP): rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours

Real Time Pricing (RTP): rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis

System Peak Response Transmission Tariff: rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges

[197] Projected Non-dispatchable demand response is not currently collected for reliability assessment.

d) Capacity, Transaction and Margin Categories

Capacity Categories

Existing

a. Certain — This category includes all existing resources reasonably anticipated to be available to operate and deliver power to or into the region.
b. Uncertain — This category includes mothballed generation and portions of intermittent generation not included in the "Existing - Certain" category.

Planned — This category includes generation that has achieved one or more of these milestones:

- Construction has started
- Regulatory permits approved
  - Site permit
  - Construction permit
  - Environmental permit
- Approved by corporate or appropriate senior management
  - Included in a capital budget
  - BOD approved

Announced/Proposed — This category includes generation that is not in a prior listed category, but has been identified through one or more of the following sources:

- Corporate or appropriate senior management announcement
- Included in integrated resource plan
- Generator Interconnection Queues

Bulk Power System Transactions

Capacity Purchases and Sales – the following categories may be applied to existing and future capacity calculations. Purchases are negative values, sales are positive values. Each interregional purchase/sale has been reported.

a) Firm – contract signed
b) Non-Firm – contract signed
c) Expected – no contract executed, but in negotiation, projected, or other.
d) Provisional – transactions under study, but negotiations have not begun.

Resource Margins

Deliverable Internal Capacity — The Sum of Existing Certain and Planned Capacity Resources.

Existing-Certain Capacity and Net Firm Transactions (MW) — Existing capacity resources reasonably anticipated to be available and operate as well as deliverable to or into the region plus net Firm Purchases/Sales.

Net Capacity Resources (MW) — Deliverable Internal Capacity, less Transmission-Limited Resources, all Derates, Energy Only resources, and Inoperable resources; plus Net Firm and Expected Purchases/Sales.

Total Potential Resources (MW) — Net Capacity Resources, plus Existing Uncertain and Proposed Capacity, less Derates, plus the net of all Purchases/Sales.

Adjusted Potential Resources (MW) — Total Potential Resources with the Total Proposed Capacity portion reduced (multiplied) by a confidence factor surrounding the certainty of Proposed Capacity.

Existing Certain Capacity and Net Firm Transactions Margin (%) — Existing-Certain Capacity and Net Firm Transactions less Net Internal Demand shown as a percent of Existing Certain Capacity and Net Firm Transactions.

Net Capacity Resources Margin (%) — Net Capacity Resources reduced by the Net Internal Demand; shown as a percent of Net Capacity Resources.

Total Potential Resources Margin (%) — Total Potential Resources reduced by the Net Internal Demand; shown as a percent of Total Potential Resources.

Adjusted Potential Resources Margin (%) — Capacity margin using the Total Potential Resources reduced (multiplied) by the confidence factor (percentage).

Target Capacity Margin (%) — Established target for capacity margin by the region or sub-region.

e) How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects:

- Adequacy — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Operating Reliability — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from creditable contingencies.

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 — customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator.
- 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. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a "rotating blackout" or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

f) Event Classifications

In order to gauge operating reliability performance and resource adequacy, a set of bulk power system event scale is used to classify bulk power system disturbances by severity, size, and impact to the general public. Events are classified using the technical requirements below as a guide.

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

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

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

a. The loss of multiple bulk power transmission components.
b. System separation with no loss of load or generation.

c. Special Protection System or Remedial Action Scheme misoperation.
d. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the ERCOT Interconnection).
e. The loss of an entire generation station or 5 or more generators.
f. The loss of an entire switching station (all lines, 100 kV or above).
g. Complete loss of dc converter station.

Category 3: An event results in any or combination of the following actions:
a. The loss of generation (2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection).
b. the loss of load (less than 1,000 MW)
c. System separation or islanding with loss of load or generation (less than 1,000 MW).
d. UFLS or UVLS operation.

Category 4: An event results in any or combination of the following actions:
a. System separation or islanding of more than 1,000 MW of load.
b. The loss of load (1,000 to 9,999 MW).

Category 5: An event results in any or combination of the following actions:
a. The occurrence of an uncontrolled or cascading blackout
b. The loss of load (10,000 MW or more)

Major Transmission Projects > 200 kV

Transmission

Terminal From Location	Terminal To Location	Line Length (Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected Service Date
ERCOT					
Jacksboro switch	W. Denton	72	345	1631	12-2006
STP	Dow	0	345	1450	03-2007
Collin Switch	NW Carrolton	19	345	1072	05-2016
Anna Switch	Collin Switch	13	345	1969	12-2008
W. Levee	Norwood	7	345	1631	12-2009
Jewett	Big Brown	0	345	1072	12-2008
P H Robinson	Oasis	0	345	1173	05-2009
Spruce	Skyline	21	345	1446	06-2009
Hutto Switch	Salado Switch	32	345	1631	06-2010
W. Denton	NW Carrolton	9	345	1631	05-2010
Lobo	San Miguel	110	345	1623	07-2009
Zorn	Hutto Switch	71	345	1630	08-2011
TNP One	Bell County SE	88	345	1631	05-2011
Temple Switch	Salado Switch	15	345	1912	05-2010
Tricorner	Seagoville Switch	9	345	1072	05-2015
Trinidad	Watermill	52	345	1072	05-2015
Krum W and Anna	Krum W	50	345	N/A	05-2015
Lobo	Rio Bravo	30	345	1939	06-2013
Venus	Cedar Hill	21	345	1912	05-2011
Oklaunion	Bowman	38	345	2724	12-2012
Ajo	Cabillo	25	345	2740	10-2008
Cagnon	Hillcountry	20	345	1171	06-2016
Sol	Rio Bravo	122	345	N/A	03-2015
N. Edinburg	Sol	15	345	N/A	03-2015
Frontera	Sol	12	345	N/A	03-2015
La Palma	Ranchito	10	345	N/A	06-2015
Frontera	South McAllen	12	345	N/A	06-2015
Ranchito	South McAllen	38	345	N/A	05-2016
Liggett	Trinity Switch	13	345	N/A	05-2015
FRCC					
Northeast	40th Street	8	230	810	09-2008
Pasadena	51st Street	1	230	810	09-2008
51st Street	40th Street	1	230	810	09-2008
St. Johns	Pringle	25	230	759	12-2008
Bayside	Gannon	0.1	230	460	04-2009
Avalon	Gifford	7	230	1141	05-2009
Bartow	Northeast Circuit 1	4	230	612	06-2009
Bartow	Northeast Circuit 2	4	230	612	06-2009
Bartow	Northeast Circuit 3	4	230	612	06-2009

Terminal From Location	Terminal To Location	Line Length (Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected Service Date
Big Bend (Plant)	Big Bend (Switching Station)	0.1	230	460	10-2009
Hines Energy Complex	West Lake Wales #2	21	230	1141	05-2010
Bithlo	Stanton (OUC)	6	230	1141	05-2010
Intercession City	West Lake Wales #2	30	230	1141	06-2010
Stanton	Bithlo	4.4	230	800	05-2011
Jax Heights Substation	Duval Substation	12.5	230	668	05-2011
Intercession City	West Lake Wales #1	30	230	1141	06-2011
Lake Agnes (TECO)	Gifford	32	230	1141	06-2011
Manatee	BobWhite	30	230	1190	12-2011
Polk Power Station	Polk Switching Station	0.7	230	650	04-2012
Bartram Substation	Switzerland Substation	6.88	230	668	05-2012
Southeast Generating Station	Bartram Substation	8.84	230	668	05-2012
Bartram Substation	Sampson Substation	4.04	230	668	05-2012
Bartram Substation	Switzerland Substation	6.88	230	668	05-2012
Polk	Pebbledale (1)	13.5	230	749	06-2012
Polk	Pebbledale (2)	9.9	230	1013	06-2012
Hopkins-Crawford 230 TAP	SUB 5 230	10	230	464	06-2012
Gilchrist Generating Station	Gilchrist Switching Station	10	230	1195	12-2012
Gilchrist Generating Station	Gilchrist Switching Station	10	230	1195	12-2012
Polk	FishHawk	28	230	1013	12-2012
Ft White	Suwannee	40	230	1141	06-2013
St. Cloud South	KUA	10	230	800	11-2015
Levy	Central FL South	50	500	2870	06-2016
Levy	Crystal River	10	500	2870	06-2016
SUB 5 230	SUB 7 230	13	230	464	06-2016
Kathleen	Lake Tarpon	45	230	1141	06-2016
Citrus	Crystal River East #1	6	230	1141	06-2016
Citrus	Crystal River East #2	6	230	1141	06-2016
Levy	Citrus #1	10	500	2870	06-2016
Levy	Citrus #2	10	500	2870	06-2016
Crystal River	Brookridge	35	230	1141	06-2016
Brookridge	Brooksville West	4	230	1141	06-2016
MRO					
Stone Lake	Arrowhead (WUMS)	79	345	1219	01-2008
Paddock	Rockdale (WUMS)	30	345	1348	2010
Gardner Park	Highway 22 (WUMS)	55	345	1425	2010
Morgan	Highway 22 (WUMS)	27	345	1425	2010
Werner West	Highway 22 (WUMS)	24	345	1425	2010
Rockdale	West Middleton (WUMS)	21	345	1195	2013
Brookings County	White	10	345	TBD	2009

Terminal From Location	Terminal To Location	Line Length (Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected Service Date
Big Stone II outlet	Granite Falls (SD/MN)	100	230	TBD	2011
Boswell	Wilton (MN)	68	230	TBD	2012
Fargo	St. Cloud (MN)	250	345	TBD	2015
Twin Cities	N. Rochester-La Crosse (MN/WI)	150	345	TBD	2015
Brookings	Twin Cities (SD/MN)	225	345	TBD	2015
Columbus East	LES NW68th & Holdrege (NE)	67	345	1195	2010
Columbus East	Shell Creek (NE)	12	345	1195	2010
Shell Creek	Hoskins (NE)	45	345	1195	2008
Wagener	NW68th & Holdrege (NE)	26	345	TBD	2009
S3458	103rd & Rokeby Road (NE)	49	345	TBD	2009
103rd & Rokeby Rd Substation		-	345	TBD	2009
Salem	Lore – Hazleton (IA)	75	345	1195	2011
South-Central Saskatchewan		99	230	TBD	2010
Conawapa	Riel DC (MH)	833	500	2	2017
Wuskwatim	Herblet Lake (MH)	86	230	420	2010
Wuskwatim	Herblet Lake (MH) circuit 2	86	230	420	2010
Herblet Lake	Ralls Island (MH)	103	230	420	2011
Dorsey	Portage South (MH)	43.5	230	284	2013
NPCC					
Coleson Cove	Salisbury	103	345		TBD
New England					
Bridgewater	Carver		345		04-2009
Pilgrim	Carver		345		04-2009
Stoughton	Mattapan		345		06-2009
Mattapan	K Street		345		06-2009
Beseck Junction	East Devon		345		08-2008
East Devon	Singer		345		12-2009
Singer	Norwalk		345		12-2009
Tewksbury	Wakefield Jct.		345		07-2009
Wakefield Jct.	Mystic		345		07-2009
Singer	Norwalk		345		12-2009
New York					
Sprain Brook	Sherman Creek	10	345	872-S/1010-W	2011-Sum
Willis 1	Patnode	9.1	230	426-S/545-W	2008/09-Win
Patnode	Duley	15.3	230	426-S/545-W	2008/09-Win
Duley	Plattsburgh	9.3	230	426-S/545-W	2008/09-Win
Willis 2	Ryan	6.5	230	426-S/545-W	2008/09-Win
Ryan	Plattsburgh	27.2	230	426-S/545-W	2008/09-Win
Princetown	S. Saratoga #3	17	345		2018

	Terminal From Location	Terminal To Location	Line Length (Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected Service Date
	Princetown	S. Saratoga #4	17	345		2018
Ontario	Outaouais	Hawthorne	25	230		06-2009
	Essa	Stayner	17	230		06-2009
	Cardiff	Hurontario	3	230		05-2010
	Hurontario	Jim Yarrow	2	230		05-2010
	Ingersoll	Woodstock	10	230		06-2010
	Bruce	Milton	115	500		03-2012
	Allanburg	Middleport	50	230		TBD
	Lakehead	Birch	13	230		2013
	Hanmer or Sudbury	Greater Toronto	180-250	500		2017
	Missisagi	Hanmer	130	230		2017
	Pinard	Hanmer	230	500		2017
	Mackay	Third Line	60	230		2017
	Nipigon	Little Jackfish	120	230		2017
	Seaforth	Goderich	25	230		2015
	Owen Sound	Bruce Peninsula	30-50	230		2015
	Manitowaning	Espanola	50	230		2015
	Nobel Series Compensation		N/A	500		12-2010
	Porcupine Static VAR Compensator		N/A	230		11-2010
Québec	Rimouski	Les Boules	34	230		12-2008
	Les Boules	Matane	58	230		12-2008
	Rimouski	Matane	5	230		12-2008
	Matane	Goemon	44	230		12-2008
	Carleton	Line2398	7.5	230		12-2008
	Les Mechins	Line 23 YY	6	230		12-2009
	Chenier	Outaouais	71	315		05-2010
	Eastmain-1A	Eastmain-1	1	315		07-2010
	Sarcelle	Eastmain-1	69	315		07-2010
	Goemon	Mont-Louis	46	315		12-2010
	Goemon	Gros Morne	56	315		12-2011
	Romaine-2	Arnaud	163	315		12-2014
	Romaine-1	Romaine-2	19	315		12-2016
RFC						
	Cranberry	Wylie Ridge	40	500	2800/3600	12-2011
	Bismarck	Troy	14	345	700	05-2010
	Goodison	Belle River	35	345	1757	12-2009
	Goodison	Pontiac	6	345	1757	12-2009
	Edenville	Warren	15	138	345	06-2010
	Argenta	Palisades 1	40	345	1238	06-2010
	Argenta	Palisades 2	40	345	1238	06-2010
	Keystone	Clearwater	23	138	345	05-2009
	Simpson	Batavia	22	138	345	12-2009
	Almeda	Saginaw River	25	138	345	05-2010
	Tippy	Chase	30	138	345	12-2010
	Algoma	Cedar Spring Jct	2	138	345	05-2011
	Croton	Cedar Spring Jct	16	138	345	05-2011
	Croton	Felch	9	138	345	12-2009

	Terminal From Location	Terminal To Location	Line Length (Miles)	Voltage Operating (kV)	Capacity Rating (MVA)	Expected Service Date
	Richland	Titabawassee	12	345	1236	04-2009
	Richland	Nelson Rd	47	345	1236	04-2009
	Possum Point	Burches Hill	3	230	TBD	06-2013
	Burches Hill	Chalk Point	19	500	TBD	06-2013
	Chalk Point	Calvert Cliffs	19	500	TBD	06-2013
	Sourth Akron	Berks	12	230	264	06-2008
	Bergen	Leonia	3	230	366	06-2008
	Branchburg	Flagtown	4	230	878	06-2008
	Roseland	Montville	7	500	3005	06-2012
	Montville	Jefferson	15	500	3005	06-2012
	Jefferson	Bushkill	22	500	3005	06-2012
	Hope Creek	Cedar Creek	12	500	3005	06-2013
	Linden	South Waterfront	6	230	873	06-2011
	Gibson	Brown	34	345	1400	12-2010
	Reid	Brown	25	345	1400	12-2010
SERC						
Central	Cumberland	Montgomery	40	500	2598	06-2008
Central	Maury	Rutherford	27	500	1732	04-2010
Central	J.K. Smith	West Garrard County	33	345	1947	12-2009
Central	Mill Creek	Hardin County	42	345	1195	12-2009
Central	Trimble County	Ghent-Speed Line	3	345	1195	03-2009
Central	Resaca	Moss Lake	9	230	265	10-2010
Central	Hardin Co.	Smith OMU	-66	345	535	02-2008
Central	Hardin Co.	Daviess Co.	59	345	535	02-2008
Central	Smith OMU	Daviess Co.	7	345	535	02-2008
Central	Brown North	West Garrard	14	345	1195	05-2009
Central	Pineville	West Garrard	89	345	1195	05-2009
Delta	Cypress	Jacinto	53	230	884	06-2012
Delta	Porter	Lewis Creek	28	230	884	06-2014
Delta	Winnfield	Danville	21	230	521	06-2014
Delta	Jacinto	Lewis Creek	29	230	884	06-2010
Delta	Franklin	Natches SES	51	230	400	06-2012
Delta	Coly	Hammond	20	230	640	09-2012
Delta	Franklin	McComb	24	230	400	06-2013
Delta	Chouteau	GRDA	100	345	954	06-2011
Gateway	Loose Creek	Mariosa Delta	11	345	1793	06-2008
Gateway	Joachim Substation	Tyson Substation	0	345	1195	10-2008
Gateway	Rush Island Plant	Joachim Substation	0	345	1200	10-2008
Gateway	Baldwin Power Plant Substation	Prairie State Power Plant	2	345	1297	06-2010
Gateway	Baldwin Power Plant Substation	Prairie State Power Plant	8	345	1297	06-2010
Gateway	Baldwin Power Plant Substation	Rush Island Plant Substation	26	345	1793	06-2010
Gateway	Prairie State Power Plant	Stallings Substation	8	345	1195	06-2010
Gateway	Prairie State Power Plant	W. Mount Vernon Substation	2	345	1195	06-2010

Southeastern	Anniston-Hammond line	North Anniston	1	230	502	03-2017
	Arkwright	West Milledgeville	33	230	866	06-2016
	Athena	Rainey	45	230	866	06-2012
	Battlefield	Frey Road	3	230	866	11-2009
	Bethabara	Clarksboro	15	230	602	12-2009
	Bethabara	East Walton	8	230	602	06-2011
	Bethbara	East Walton (black)	6	230	602	06-2014
	Bostwick	East Walton	4	230	602	06-2011
	Bowen	Villa Rica	28	230	1578	06-2009
	Braselton	Sharon Church	3	230	602	06-2008
	Bucks SS	Tensaw SS	9	230	865	08-2009
	Calvert SS	Tensaw SS	5	230	865	05-2009
	Camp Creek	Cliftondale	5	230	602	10-2008
	Clermont Jct	South Cleveland	17	230	602	06-2014
	Clermont Jct.	South Cleveland	23	230	602	06-2014
	Clermont Junction	Dawson Crossing	20	230	602	08-2012
	Cliftondale	Ono	6	230	602	06-2013
	Cumming	Sharon Springs	7	230	602	06-2011
	Dawson Crossing	Palmer Creek	4	230	602	06-2008
	Deptford	Kraft	13	230	433	06-2011
	Dorsett	Jct-57a Substation	11	230	602	06-2013
	Dum Jon	Thomson Primary	23	230	596	06-2010
	East Lake Road	Jackson Creek	9	230	602	06-2010
	East Lake Road	Ola	4	230	602	06-2010
	East Walton	Jack's Creek	9	230	602	06-2011
	East Walton	Rockville	40	500	3464	06-2011
	Ellicott TS	West McIntosh	1	230	602	12-2008
	Ellijay Primary	Cherry Log	12	230	602	06-2012
	Farley	Raccoon Creek	60	230	602	06-2013
	Farley-Scholz line	Cottonwood TS	1	230	502	04-2011
	Forrest Road	West Milledgeville	35	230	602	06-2015
	Frey Road	Huntsville	5	230	866	11-2009
	Gaston	Bessemer	1	230	502	04-2009
	Gordon	North Dublin	32	230	602	06-2014
	Homeland	Kettle Creek	36	230	602	06-2008
	Hopewell	McGrau Ford (black)	11	230	602	06-2013
	Jack's Creek	Cornish Mountain	15	230	602	06-2011
	JC Penny tap	JC Penny	2	230	602	06-2014
	Jim Moore Road	Sharon Church	11	230	602	06-2010
	Kiln	Carriere SW	26	230	602	06-2011
	Klondike	Jackson Creek	4	230	602	06-2008
	Laguna Beach	Santa Rosa	22	230	602	06-2012
	Lansing Smith	Laguna Beach	14	230	602	06-2010
	Line Creek	Ono	6	230	602	06-2014
	LPM-Monroe-str 31	Str. 31 (Cornish Mountain)	4	230	580	06-2011
	McConnell Road	Woodlore	5	230	866	06-2009
	McDonough	Ola	10	230	602	06-2015
	McGrau Ford	Hopewell	12	230	602	06-2015
	Mitchell	Slappy Drive	13	230	602	05-2016

	O'Hara	McDonough	20	230	602	06-2014
	Ono	Line Creek	3	230	602	06-2013
	Pegamore	Huntsville	2	230	866	06-2010
	Plant McDonough	Smyrna	6	230	1205	06-2010
	Plant McDonough CC	Plant McDonough (black)	1	230	1205	06-2011
	Plant McDonough CC	Plant McDonough (white)	1	230	1205	06-2011
	Prattville CT TS	County Line Road TS	1	230	1003	10-2013
	Shoal Creek	Suwanee	8	230	602	06-2013
	South Dahlonega	Palmer Creek	8	230	602	06-2014
	South Hall	Suwanee	10	230	664	06-2016
	Thomson	Warthen	35	500	3464	06-2010
	Thomson Primary	Vogtle	50	500	2701	06-2016
	Vogtle	Thomson	70	500	3464	06-2015
	Woodlore	Battlefield	3	230	866	06-2009
VACAR	Brambleton	Greenway	11	230	796	05-2008
	Bennettsville	Bennettsville (PEC)	2	230	956	05-2008
	Clarendon	Rosslyn	1	230	600	05-2008
	Durham	Falls	8	230	1195	06-2008
	Cross	Aiken	88	230	956	06-2008
	Kingstree	Lake City	13	230	956	01-2009
	Denny Terrace	Pineland	8	230	950	05-2009
	Rockingham	Wadesboro Bowman School	12	230	1256	06-2009
	Bristers	Gainesville	15	230	1047	06-2009
	Chickahominy	Old Church	16	230	797	11-2009
	A M Williams	Mt Pleasant	17	230	352	05-2010
	Hamilton	Pleasant View	12	230	800	05-2010
	Harrisonburg	Valley	11	230	797	05-2010
	Clinton	Lee	26	230	628	06-2010
	Chickahominy	Lanexa	14	230	722	06-2010
	Asheville	Enka	5	230	566	12-2010
	Rockingham	West End	38	230	1195	06-2011
	Kinston DuPont	Greenville	30	230	628	06-2011
	Asheboro	Pleasant Garden	22	230	1195	06-2011
	Harris	RTP	22	230	1195	06-2011
	Pleasant Garden	Asheboro	20	230	1100	06-2011
	Rockingham	Lilesville	14	230	1195	06-2011
	Loudoun	Mt Storm	100	500	3450	06-2011
	Carson	Suffolk	50	500	3450	06-2011
	Suffolk	Thrasher	26	230	1047	06-2011
	Bristers	Garrisonville	13	230	1047	06-2011
	Gainesville	Remington	25	230	1047	04-2012
	Pepperhill	Summerville	7	230	950	05-2012
	Elizabeth City	Shawboro	10	230	1047	06-2012
	Winyah	Campfield	14	230	956	12-2012
	Canadys	Church Creek	38	230	950	12-2013
	Canadys	Pepperhill	35	230	950	12-2013
	Pepperhill	Church Creek	16	230	950	12-2013
	VC Summer	VC Summer #2	1	230	950	12-2013

	VC Summer	VC Summer #2	1	230	950	12-2013
	Canadys	Church Creek	-38	230	352	12-2013
	Reeves Avenue	Sewells Point	11	230	1047	05-2015
	Landstown	Virginia Beach	11	230	800	05-2015
	Clark	Idylwood	4	230	515	05-2015
	VC Summer	Killian	38	230	950	12-2015
	VC Summer #2	Lake Murray	19	230	950	12-2015
	Denny Terrace	Lyles	3	230	950	12-2015
	Urquhart	Graniteville	18	230	950	05-2016
	Urquhart	Graniteville	-38	230	352	05-2016
	Bristers	Possum Point	35	500	3464	05-2016
	Chesterfield	Midlothian	22	230	1047	05-2016
	Cape Fear	Siler City	30	230	628	06-2017
	Florence	Marion (PEC)	26	230	628	06-2017
SPP						
	Blackberry	Chouteau	108	345	1099	06-2010
	Chouteau	GRDA1	5	345	1099	06-2010
	Chamber Springs	Tonitown	14	345	1176	06-2008
	Turk	NW Texarkana	34	345	1778	06-2011
	Centerton	Oasge Creek	41	345	440	06-2016
	Sooner	OK/KS Border	53	345	1052	12-2010
	Valiant	Hugo	19	345	956	12-2008
	Wichita	Reno County	40	345	1468	12-2008
	Reno County	Summit	51	345	956	12-2009
	Rose Hill	OK/KS Border	53	345	1052	12-2010
	Potash Junction Interchange	Pecos Interchange	16	230	541	06-2009
	Seven Rivers Interchange	Pecos Interchange	18	230	541	06-2009
	Pringle Interchange	Hitchland	34	230	541	12-2010
	Moore Co	Hitchland	50	230	541	12-2010
	Hitchland	Perryton	35	230	541	12-2010
	ELK CITY	Stateline 6	48	230	351	06-2010
	Grapevine Interchange	Stateline 6	48	230	351	06-2010
	Mustang Station	Seminole	21	230	541	06-2009
	Hobbs	Seminole	45	230	541	06-2010
WECC						
NWPP	Montana	Alberta	80	230	TBD	05-2009
NWPP	Montana	Alberta	135	230	TBD	05-2009
NWPP	Northwest Alberta Reinforcement		83	144	330/422	04-2010
NWPP	Northwest Alberta Reinforcement		145	240	TBD	04-2010
NWPP	Midpoint	Boise Bench: Loop King	80	230	TBD	06-2010
NWPP	Populus	Terminal	135	345	TBD	06-2010
NWPP	Gonder	Harry Allen	250	525	3000	06-2012
NWPP	Northwest Alberta Reinforcement		135	144	TBD	04-2011
NWPP	East Kootenay Reinforcement		80	230	TBD	10-2011
NWPP	Edmonton	Calgary Transmission Reinforcement	206	500	3000	11-2011

	Rock Springs, WY	American Falls, ID	1041	500	TBD	06-2012
	Hemingway	Boardman	202	500	3000	06-2012
	Mountain States Transmission Intertie		460	500	1500	01-2013
	Pearl Transmission Station		78	230	394	05-2014
	Shoshone, ID	Walters Ferry, ID	126	500	3000	06-2014
	Nicola, BC	Meridian, BC	153	500	TBD	10-2014
RMPA	Donkey Creek	Pumpkin Buttes	75	230	TBD	10-2008
	Hughes	Sheridan	105	230	460	12-2009
	Miracle Mile	Ault	146	239	402	12-2009
	Comanche	Midway	50	230	506	05-2010
	Comanche	Daniels Park	125	345	1200	05-2010
	Comanche	Daniels Park	125	345	1200	05-2010
	Midway	Waterton	82	345	1200	11-2010
	San Luis Valley	Walsenburg	80	230	613	12-2011
	Pawnee	Smoky Hill	96	345	735	05-2013
AZ / NM / SNV	Southeast Valley Project		51	500	1405	06-2008
	Navajo Transmission Project		189	500	1300	04-2009
	Navajo Transmission Project		62	500	1300	12-2010
	Southeast Valley Project		87	500	1405	05-2011
	Centennial II Project		61	525	3000	06-2011
	Navajo Transmission Project		218	500	1300	12-2011
	Palo Verde	North Gila	115	500	1200	06-2012
	Tortolita	Vail	60	345	925	06-2014
CA / MX	Metcalf	Moss Landing Reconductoring	70	230	TBD	12-2008
	Big Creek 3	Rector	75	230	460	04-2009
	Palo Verde	Devers	225	500	TBD	06-2011
	IPPDC Upgrade		488	± 500	TBD	07-2009
	Sunrise Powerlink (IV-Central)		100	500	TBD	06-2011
	Barren Ridge	Castaic	72	230	TBD	07-2005
	Barren Ridge	Castaic	234	230	TBD	07-2005
	Green Path North		85	500	TBD	11-2013
	La Jovita, MX	La Herradura MX	50	230	430	10-2013
	El Cañon, MX	El Ciprés, MX	52	230	430	06-2015

Transformers

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
ERCOT				
Seagoville Switch 345/138 kV autotransformer	345	138	12-2008	Replace the existing 345/138 kV autotransformer
Roanoke Switching Station #1 345/138 kV autotransformer replacement	345	138	05-2009	Replace existing 345/138 kV autotransformer
Tyler Grande 345/138 kV Switching Station	345	138	05-2009	Construct switching station and install a 345/138 kV autotransformer, 138 kV capacitor and 138 kV series reactor
Second Whitney 345/138 Autotransformer	345	138	09-2009	Install second 450MVA 345/138KV auto at Whitney
Second Concord 345/138 Autotransformer	345	138	09-2009	Install second 300MVA 345/138KV auto at Concord
CenterPoint Energy/TNMP Alvin interconnection	345	138	10-2009	Build a new 345 kV, 3 breaker ring bus South Alvin substation looped into ckt.99 P.H. Robinson - Oasis. Add 345/138 kV autotransformer at new South Alvin substation interconnect with TNMP 138 kV North Alvin bus.
Skyline - Install a Third 345kV Autotransformer	345	138	11-2009	Install one 600 MVA autotransformer.
Lobo, build 345 kV for 675MVA autotransformer	345	138	12-2009	Construct new Laredo Lobo to San Miguel 345 kV line with Laredo Lobo 345/138 kV substation where the existing Falfurrias to Laredo 138 kV and the Freer to Laredo 69 kV transmission lines cross Highway 59, rebuild Laredo Lobo to Laredo 138 kV line and convert Lobo to Laredo 69 kV line section to 138 kV
Eagle Mountain 345/138 kV autotransformer	345	138	05-2010	Install second 345/138 kV autotransformer
Rothwood 345/138 kV substation	345	138	05-2010	Build a new 345/138 kV Rothwood substation. Loop ckt.74 Kuykendahl to King and 138 kV ckt.66 Rayford tap section into the new substation. Add one 800 MVA 345/138 kV autotransformer at Rothwood substation.
Hutto Switch and 345/138 kV autotransformer	345	138	06-2010	Create 345 kV switching station and install a 345/138 kV autotransformer

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Lytton Springs Autotransformer Addition	345	138	06-2010	Add a new 345-138 kV 478 MVA autotransformer at the Lytton Springs substation (9074). Terminate the Mendoza (7325) - Turnersville (7500) 138 kV transmission line (T-382) into the Lytton Springs substation 138 kV bus (9075), creating the new Turnersville (7500) - Lytton Springs (9075) and Mendoza (7325) - Lytton Springs (9075) 138 kV transmission lines. Upgrade the new Turnersville (7500) - Lytton Springs (9075) 138 kV transmission line from 795 ACSR (220MVA) to 1433 ACSS/TW (507 MVA). Upgrade the new Mendoza (7325) - Lytton Springs (9075) 138 kV transmission line from 795 ACSR (220 MVA) to bundled 795 ACSR (440 MVA).
Sargent Road 345/138 kV autotransformer	345	138	05-2011	Install second 345/138 kV autotransformer
N Edinburg to Frontera, build 345 kV dbl crct Line	345	138	05-2011	Addition North Edinburg to Frontera 345 kV line with bundled 1590 ACSR and double circuit capable structures and 345/138 kV substation at Frontera
2nd Lewisville Auto	345		06-2011	Install (2nd) 345/138 kV autotransformer at Lewisville station
Gilleland 345/138kV autotransformer	345	138	06-2011	Install a 600 MVA 345/138kV autotransformer at the new Gilleland switching substation
Gilleland 345/138 kV Project	345	138	06-2012	Establish a 345kV switching station adjacent to LCRA's Gilleland station. Establish a new 138kV circuit from Gilleland to Techridge and maintain a normally close tie between AEN and LCRA's switchyard at Gilleland.
Dunlap Autotransformer	345	138	08-2012	The original proposal is to add the 3rd autotransformer at Austrop. The extended outage necessary for the project has resulted in the alternative to install a 600MVA auto at the Dunlap substation. The Clear Springs to Gilleland 345kV circuit will terminate on the 345kV bus at Dunlap. In addition, the existing ckt 921 will be converted to 345kV and terminate at the 345kV bus at Dunlap.
Cagnon - Install a Third 345kV Autotransformer	345	138	06-2013	Install one 600 MVA autotransformer.
North McCamey Three 345/138 kV autotransformers	345	138	06-2013	12/02 plan recommends the addition of Three 345/138kV autotransformers North McCamey
Lobo to Rio Bravo, build 345 kV line	345	138	06-2013	Construct 345 kV line from Lobo to Rio Bravo and add 345/138 kV substation at Rio Bravo with 345/138 kV autotransformer

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Zorn Autotransformer Addition	345	138	06-2013	Add a new 345-138 kV 478 MVA autotransformer at the Zorn substation (7042).
Rio Bravo, 345 kV SS with 345/138 kV autotransformer	345	138	03-2015	Construct 345 kV line from Lobo to Rio Bravo and add 345/138 kV substation at Rio Bravo with 345/138 kV autotransformer
Frontera, add SS with 345/138 kV autotransformer	345	138	03-2015	Addition North Edinburg to Frontera to South McAllen 345 kV line with bundled 1590 ACSR conductor and double circuit capable structures and 345/138 kV substation at Frontera
Sol, Build 345 KV SS	345	138	03-2015	Construct 345 kV line from Rio Bravo to Sol to N Edinburg and add 345/138 kV substation at Rio Bravo with 345/138 kV autotransformer
Trinity Switch 345/138 kV autotransformer	345	138	05-2015	Create Trinity Switch and install a 600 MVA 345/138 kV autotransformer
Lavon 345/138 kV Switching Station	345	138	05-2015	Construct 345/138 kV switching station
Liggett 345/138 kV autotransformer	345	138	05-2015	Replace the existing 450 MVA 345/138 kV autransformer
Collin 345/138 kV autotransformer	345	138	05-2015	Install second 345/138 kV autotransformer
North Lake 345/138 kV autotransformer	345	138	05-2015	Install a 345/138 kV autotransformer
Loma Alta 345kV station and autotransformer	345	138	06-2015	Construct a 345 substation and connect to the existing Loma Alta 138 substation.
Ranchito, New SS with 345/138 kV autotransformer	345	138	06-2015	Construct 345 kV line from LaPalma to Ranchito to South McAllen and add 345/138/69 kV substation adjacent to existing Cavazos 69 kV substation with 600 MVA 345/138 kV autotransformer
South McAllen, new SS with 345/138 kV autotransformer	345	138	06-2015	Add Frontera to South McAllen 345 kV line with bundled 1590 ACSR and double circuit capable structures and 345/138 kV substations at Frontera and South McAllen
FRCC				
Central Florida south transformer	500	230	Summer 2016	Planned
Alico transformer	230	138	Winter 2008/09	Planned
Buckingham transformer	230	138	Winter 2009/10	Planned
Normandy transformer	230	138	Summer 2008	Active
Center Park transformer	230	138	Summer 2010	Planned

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
MRO				
Oak Creek Transformer No. 2 (WUMS)	345	138	2009	Add 2nd Transformer / Planned
Kewaunee Transformer No. 2 (WUMS)	345	138	2011	Add 2nd Transformer / Provisional
West Middleton Transformer No. 1 (WUMS)	345	138	2013	New Transformer / Planned
North Randolph Transformer No. 1 (WUMS)	345	138	2018	New Transformer / Provisional
Shell Creek Transformer (NE)	345	230	2008	New Transformer / Planned
Hoskins Transformer (NE)	345	230	2008	New Transformer / Planned
Columbus East Transformer (NE)	345	115	2010	New Transformer / Planned
Grand Island Transformer (NE)	345	230	2009	New Transformer / Planned
North Platte Transformer (NE)	230	115	2009	New Transformer / Planned
NW68th&Holdrege Transformer (NE)	345	115	2010	New Transformer / Proposed
Salem 345/161 kV transformer (IA)	345	161	2009	New Transformer / Planned
Hazleton 345/161 kV transformer #1 (IA)	345	161	2010	New Transformer / Planned
Lore 345/161 kV transformer (IA)	345	161	2012	New Transformer / Planned
South-Central Saskatchewan (SPC)	230	138	2010	New Transformer / Planned
Transcona Transformer (MH)	230	66	2010	New Transformer / Planned
Transcona Transformer2 (MH)	230	66	2010	New Transformer / Planned
Stanley Transformer (MH)	230	66	2010	New Transformer / Planned
Neepawa Transformer (MH)	230	66	2011	New Transformer / Proposed
Riel Transformer (MH)	500	230	2012	New Transformer / Planned
NPCC				
Fitzwilliam	345	115	12-2008	Under Construction
Wachusett	345	115	06-2011	Planned
Berry Street	345	115	03-2011	Concept
Norwalk	345	115	12-2008	Under Construction
Singer	345	115	12-2009	Under Construction
Singer	345	115	12-2009	Under Construction
Wakefield Junction	345	115	06-2009	Under Construction
Wakefield Junction	345	115	06-2009	Under Construction
Wakefield Junction	345	115	06-2009	Under Construction
Wakefield Junction	345	115	06-2009	Under Construction

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Auburn Street	345	115	06-2010	Concept
Lapeer	345	115	2010-Winter	Planned
Lapeer	345	115	2010-Winter	Planned
Lovett	345	138	Before 2013	Planned
RFC				
Cumberland	230	138	05-2009	New
Marquis	345	138	06-2009	Add 450 MVA
Conesville	345	138	12-2008	New 675 MVA
Jug Street	345	138	12-2009	New 450 MVA
Twin Branch	345	138	06-2009	New 675 MVA
Matt Funk	345	138	06-2011	New 675 MVA
Sporn	345	138	12-2009	New 450 MVA
Prexy	500	138	06-2011	New
Kammer	765	500	11-2009	Replacement
Doubs Bank #2	500	230	05-2011	Replacement
Doubs Bank #3	500	230	05-2011	Replacement
Doubs Bank #4	500	230	05-2011	Replacement
Waugh Chapel	500	230	06-2012	Replacement
Lisle	345	138	05-2010	New
Qualitech	345	138	06-2010	New
Logans Ferry	345	138	06-2010	New
Brady	345	138	06-2012	New
Red Lion	230	138	05-2009	New 300 MVA
Indian River	230	138	06-2011	New
Avon	345	138	06-2009	New 400 MVA
Tangy	345	138	06-2009	New
Cranberry	500	138	06-2013	New 600 MVA
Worthington	161	138	09-2009	Add capacity
Decatur Switch Station	161	138	12-2009	New
Bunce Creek	220	220	05-2009	Replace failed PAR
Tallmadge #3	345	138	12-2008	New
Richland	345	138	04-2009	New

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Hiple #2	345	138	08-2008	New
St. John #2	345	138	12-2011	New
Brighton #2	500	230	06-2009	New
Burches Hill #2	500	230	06-2011	New
Burches Hill #3	500	230	12-2011	New
Brighton	500	230	06-2012	Replacement
Metuchen	230	138	01-2009	New
Roseland	230	138	06-2009	Upgrade
Roseland	230	138	02-2010	Upgrade
Roseland #1	500	230	06-2012	New
Roseland #2	500	230	06-2012	New
Brown	345	138	12-2012	New
SERC				
Rutherford 500kV Substation	500	161	06-2010	Planned
Jackson 500kV Substation	500	161	06-2011	Planned 2nd Transformer
Clay County, MS 500kV Substation	500	161	06-2011	Planned
Hardin County 345kV Substation	345	138	05-2011	Planned-2nd Transformer
Middletown 345kV Substation	345	138	05-2017	Planned-4th Transformer
West Garrard 345kV Substation	345		12-2009	Planned
JK Smith Power Plant	345	138	2008	Planned
Marion County 161kV Substation	161	138	2008	Planned
Brookline 345 kV Substation	345	161	Summer 2008	Planned
Joachim Substation	345	138	Fall 2008	Planned
Gray Summit Substation	345	138	Winter 2010	Planned-2nd Transformer
South Bloomington, (IL) Substation	345	138	Winter 2012	Planned-
Fargo (Northwest Peoria, IL) Substation	345	138	Winter 2013	Proposed
Bonaire 230/115 kV Transformer	230	115	Fall 2008	Planned-Replacement
Sinai Cemetery 230/115 kV Transformer	230	115	Summer 2008	Planned
Gordon 230/115 kV Transformer	230	115	Summer 2008	Planned
Miller Bayou 230/115 kV Transformer	230	115	Summer 2008	Planned
Boulevard 230/115 kV Transformer	230	115	Winter 2008	Planned

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Elsanor 230/115 kV Transformer	230	115	Summer 2009	Planned
Thompson 500/230 kV Transformer	500	230	Summer 2010	Planned
Brentwood 230/115 kV Transformer	230	115	Summer 2010	Planned
Deptford 230/115 kV Transformer	230	115	Summer 2011	Planned
Lansing Smith 230/115 kV	230	115	Summer 2011	Planned
Smyrna 230/115 kV Transformer	230	115	Summer 2011	Planned
Santa Rosa 230/115 kV Transformer	230	115	Summer 2012	Planned
Peachtree 230/115 kV Transformer	230	115	Summer 2012	Planned
Meldrim 230/115 kV Transformer	230	115	Summer 2012	Planned
Jct-57a 230/115 kV Transformer	230	115	Summer 2013	Planned
Gainesville #2 230/115 kV Transformer	230	115	Summer 2013	Planned
Nelson 230/115 kV Transformer	230	115	Summer 2013	Planned
Sweatt 230/115 kV Transformer	230	115	Summer 2013	Planned
Buzzard Roost 230/115 kV Transformer	230	115	Summer 2013	Planned
Greene County 230/115 kV Transformer	230	115	Summer 2013	Planned
East Point 230/115 kV Transformer	230	115	Summer 2014	Planned
JC Penney 230/115 kV Transformer	230	115	Summer 2014	Planned
McDonough 230/115 kV Transformer	230	115	Summer 2014	Planned
McConnel Road 230/115 kV Transformer	230	115	Summer 2014	Planned
Roswell 230/115 kV Transformer	230	115	Summer 2014	Planned
South Cleveland 230/115 kV Transformer	230	115	Summer 2014	Planned
South Macon 230/115 kV Transformer	230	115	Summer 2014	Planned
McIntosh 230/115 kV Transformer	230	115	Summer 2015	Planned
Offerman 230/115 kV Transformer	230	115	Summer 2015	Planned
O'Hara 500/230 kV Transformer	500	230	Summer 2016	Planned
Middlefork 500/230 kV Transformer	500	230	Summer 2016	Planned
Arkwright 230/115 kV Transformer	230	115	Summer 2016	Planned
Woodstock 230/115 kV Transformer	230	115	Summer 2016	Planned
Slappy Drive 230/115 kV Transformer	230	115	Summer 2016	Planned

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
County Line Road 230/115 kV Transformer	230	115	Summer 2017	Planned
Silverhill 230/115 kV Transformer	230	115	Spring 2018	Planned
Holt 230/115 kV Transformer	230	115	Summer 2018	Planned
Bay Creek 230/115 kV Transformer	230	115	Summer 2018	Planned
Bluffton 230/115 kV Substation	230	115	Summer 2008	Planned-Replacement
Durham 500 kV Substation	500		Summer 2008	Planned
Hopkins 230/115 kV Substation	230	115	Summer 2008	Planned
SPP				
Southwest Shrevport 345 kV Transformer	345	138	Spring 2009	Planned
Turk 345 kV Transformer	345	138	Summer 2011	Planned
Centerton 345/161kV Transformer	345	161	Summer 2014	Planned
Flint Creek 345/161 kV Transformer	345	161	Summer 2010	Planned
Osage Creek 345/161kV Transformer	345	161	Summer 2014	Planned
Johnson Coutny 345/138 kV Transformer	345	138	Summer 2011	Planned
Valiant 345/138 kV Transformer	345	138	Summer 2010	Planned
Hitchland 345/230 kV Transformer	345	230	Summer 2010	Planned
Reno County 345/115 kV Ckt 1 Transformer	345	115	Winter 2008	Planned
Reno County 345/115 kV Ckt 2 Transformer	345	115	Winter 2009	Planned
Stranger Creek 345/115 kV #2 Transformer	345	115	Summer 2009	Planned
Rose Hill 345/138 kV #3 Transformer	345	138	Summer 2011	Planned
Spearville 345/230 kV #2 Transformer	345	230	Winter 2013	Planned
West Gardner 345/161 kV Transformer	345	161	Summer 2008	Planned
WECC				
Mora Substation	230	138	05-2008	230/138 kV auto-transformer.
Mill Creek Phase Shifter	230	-	06-2008	Phase Shifter
Lower Valley Reinforcement Project (Hooper Springs)	138	-	10-2008	A 138/115 kV transformer. Part of the Lower Valley Project. Joint project with PAC.

Transformer Project Name	High-Side Voltage (kV)	Low-Side Voltage (kV)	In-Service Date(s)	Description/Status
Three Peaks 345/138kV transformer	345	138	06-2009	
Oquirrh 345kV/138kV transformer	345	138	06 2009	Capacity addition for potential Vineyard area generation addition.
Caribou 345kV/138kV transformer	345	138	06-2009	Transformer to be located at new Caribou 345 kV Substation
Sunset Auto-transformer	230	-	06-2009	Install a 230/115 kV, 320 MVA auto transformer at Sunset Substation and construct a new 230 kV line from Keeler Sub to Sunset Sub.
King Substation	230	138	06-2010	
Terminal 345/138kV transformer #1	345	138	05-2012	
Terminal 345/138kV transformer #2	345	138	05-2012	
Gateway West Transm.	500	345	06-2012	
Midvalley 345/138kV transformer #1	345	138	05-2013	
Midvalley 345/138kV transformer #2	345	138	05-2013	
Selkirk Transformer Addition	500	230	10-2008	Add transformer T4
Montana - Alberta Tie	230	-	05-2009	
Selkirk Transormer Addition	500	230	10-2010	Add transformer T4
West Loop Switching Station	345	230	06-2008	345 / 230 kV transformer.
Palo Verde – Pinal West Project	500	-	05-2008	
Southeast Valley Project	230	-	05-2008	
McDonald 230/138kV Transformer	230	138	03-2009	Load service to McDonald
Springerville #4	500	-	05-2009	
Northwest 230/138 kV Transformer	230	138	06-2009	
Sinatra 230/138 kV Transformer	230	138	06-2009	
Northwest 500/230 kV Transformer	500	230	06-2010	
Sunrise 500/230 kV Transformer	500	230	06-2011	
Southeast Valley Project	500	-	06-2011	
Lone Tree Substation Interconnection	230	-	05-2008	Meet customer demand and improve service reliability.
Rancho Vista Substation	500	230	06-2009	500/230 kV transformer bank.
Rancho Vista Substation	500	230	06-2009	500/230 kV transformer bank.
Sunrise Powerlink	230	230	06-2011	New substation, 500/230kV 500/230/12 kV xfmr banks
Sunrise Powerlink	500	230	06-2011	New substation, 500/230kV 500/230/12 kV xfmr banks

Report Content Responsibility

The following NERC industry groups have provided input into NERC's *2008 Long-Term Reliability Assessment*:

NERC Group	Relationship	Contribution	Action
Planning Committee (PC)	Reports to NERC's Board of Trustees	• Review 2008 LTRA • Risk Assessment of Emerging Issues • Improvement Plan	• Endorse • Completed • Approve
Reliability Assessment Improvement Task Force	Reports to the PC	• Develop Reliability Enhancement Plan	• Report
Reliability Assessment Subcommittee (RAS)	Reports to the PC	• Peer Reviews • Develop Emerging Issues	• Report • Completed
Data Coordination Working Group	Report to RAS	• Develop data and regional reliability narrative requests	• Completed
Load Forecasting Working Group	Reports to RAS	• Develop load forecasting bandwidths	• Completed
Resource Issues Subcommittee (RIS)	Reports to PC	• Develop Emerging Issues • Demand Resources	• Completed • Report
Demand Side Management Task Force	Reports to RIS	• Demand Reponses collection taxonomy	• Completed
Operating Committee (OC)	Reports to NERC's Board of Trustees	• Reviewed *Reliability Trends* section	• Completed
Reliability Metrics Working Group	Reports to the PC and OC	• Reviewed the reliability trends Metrics	• Completed
Integration of Variable Generation Task Force	Reports to the PC and OC	• Integration of variable generation	• Ongoing
Board of Trustees	NERC's Independent Board	• Review the 2008 LTRA • Approve for publication	• Completed

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Errata

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Page 7: Capacity Resources & Margins Quick Reference Guide

Total Internal Capacity was used in error. This term was changed to Deliverable Internal Capacity (calculated during the data collection process) as it was this capacity figure that was used to define Net Capacity Resources, Potential Resources, and Adjusted Potential Resources. Deliverable Internal Capacity is defined as the sum of Existing Certain and Planned Resources. The error did not occur in the calculations. Total Internal Capacity was removed from the list of terms, as this value is not used anywhere in the report.

Page 19: Figure 9: Ancillary Demand Response – 10 Year Projection

The values reported for NPCC as demand response used for ancillary services, were incorrect due to a data submittal error. Upon resubmission, the New York Subregion in NPCC has reported 0 MW of demand response being used for ancillary services. The values previously reported were spinning and non-spinning reserve requirements.

Page 74: Notes for Table 13a through 13f

Clarification was needed to address a reported discrepancy in the data for RFC, PJM, and MISO. Net Internal Demand for PJM and MISO are reported on a coincident peak basis. However, RFC reports a non-coincident peak demand. This accounts for the discrepancy when summing PJM and MISO loads.