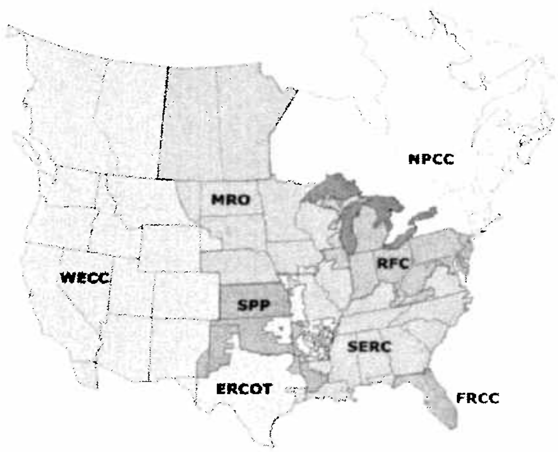
NERC's Mission

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.

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[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.

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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).

Total Internal Capacity — Sum of Existing (both Certain and Uncertain) and Planned Capacity.

Net Capacity Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources, all Derates, Energy Only, and Inoperable resources; including Net Firm, Expected and Provisional Purchases/Sales (does not include Non-Firm Purchases/Sales).

Total Potential Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources, plus all Purchases/Sales.

Adjusted Potential Resources (MW) —Total Proposed Resources reduced (multiplied) by a confidence factor; plus Net Non-Firm Transactions.

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

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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).

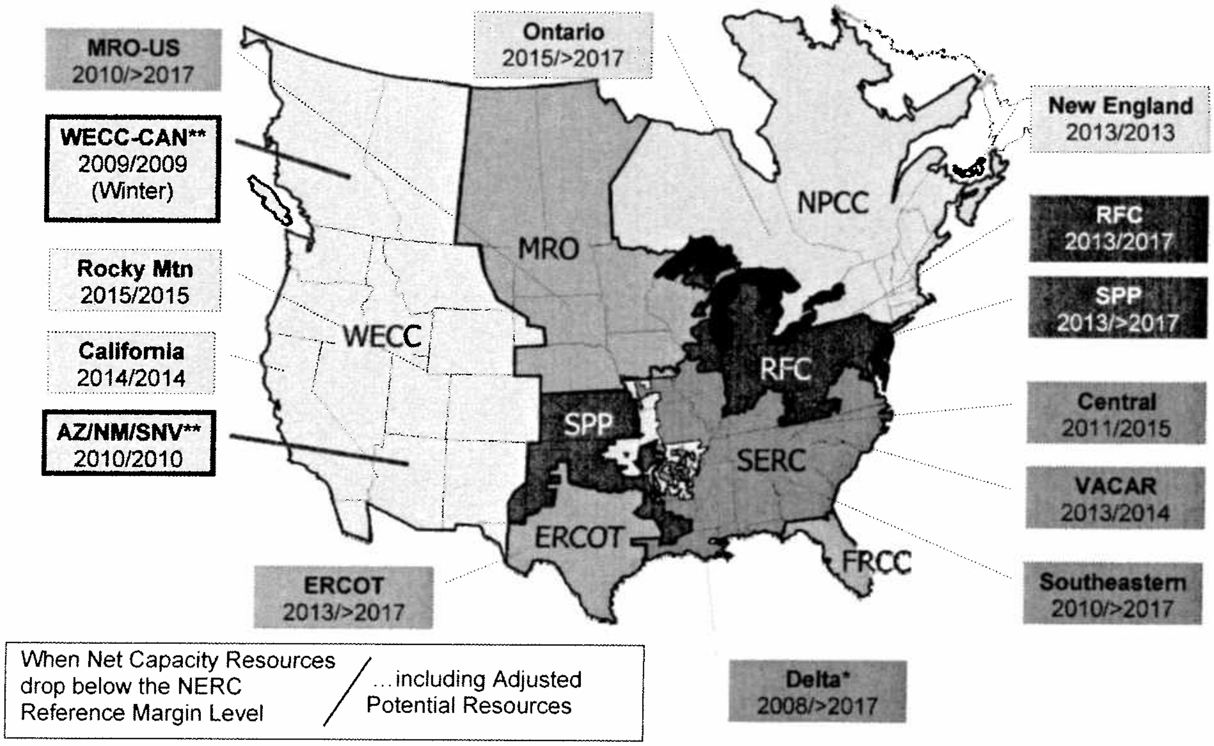
Key Findings for 2008-2017

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.

[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.

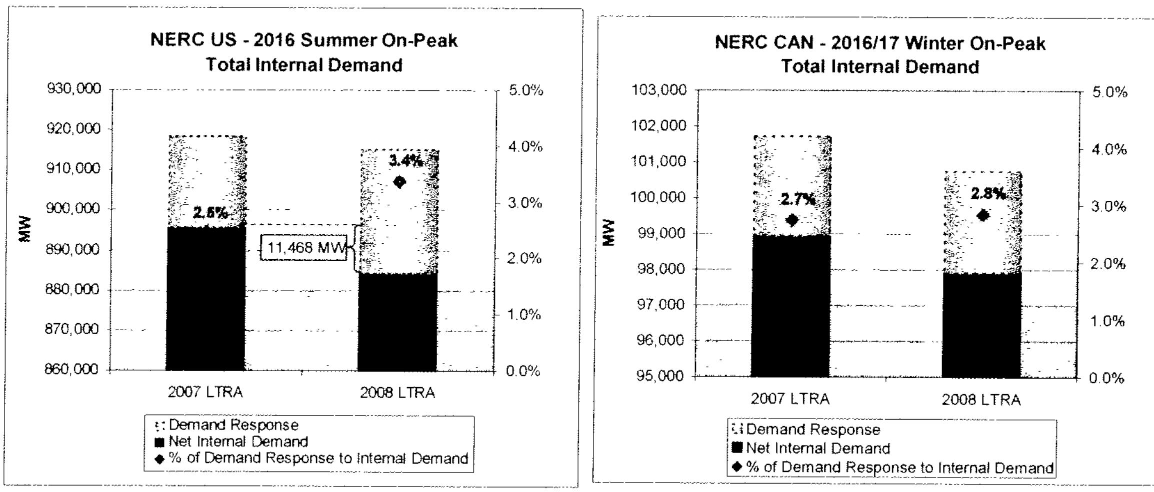
A significant decrease in projected demand growth in the U.S. also contributes to higher capacity margins over the ten year period. This is primarily due to an increase in projected demand-side management (DSM) which plays a key role in improving capacity margins over the ten years. Summer peak demand 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.

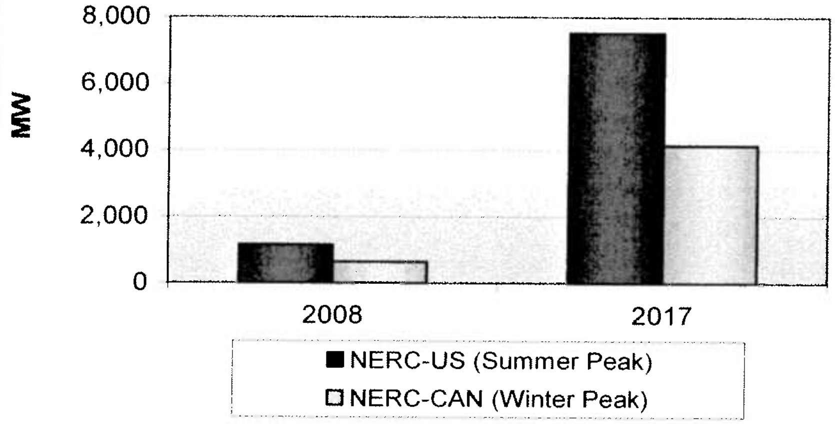
Figure 2: Dispatchable Capacity Demand Response Resources for the U.S. (2016 Summer peak) and Canada (2016/17 Winter peak)



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

Figure 3: 2008-2017 Project New Energy Efficiency in the U.S. and Canada



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

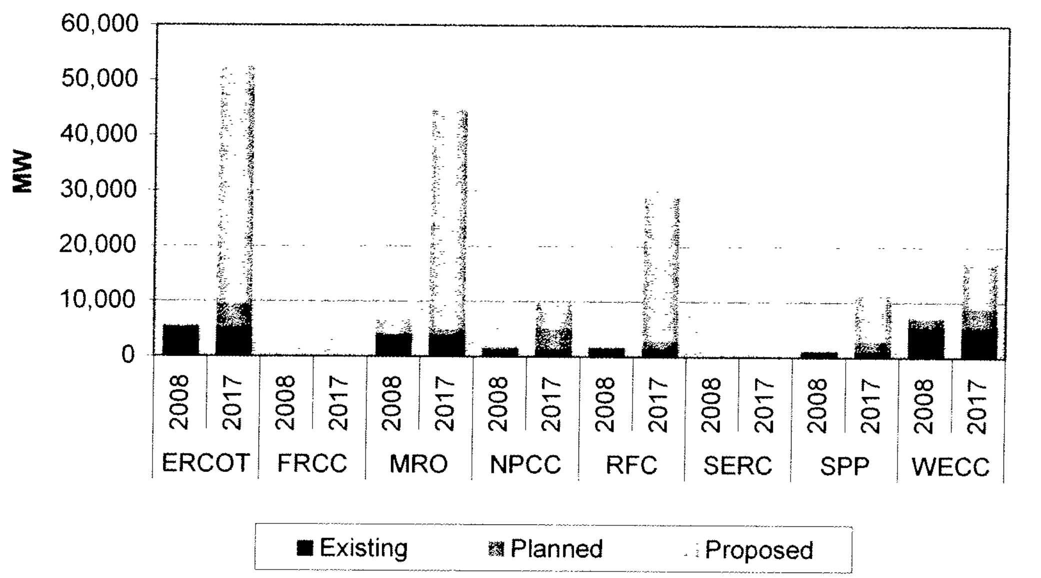
2. Wind Capacity Projected to Significantly Increase

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.

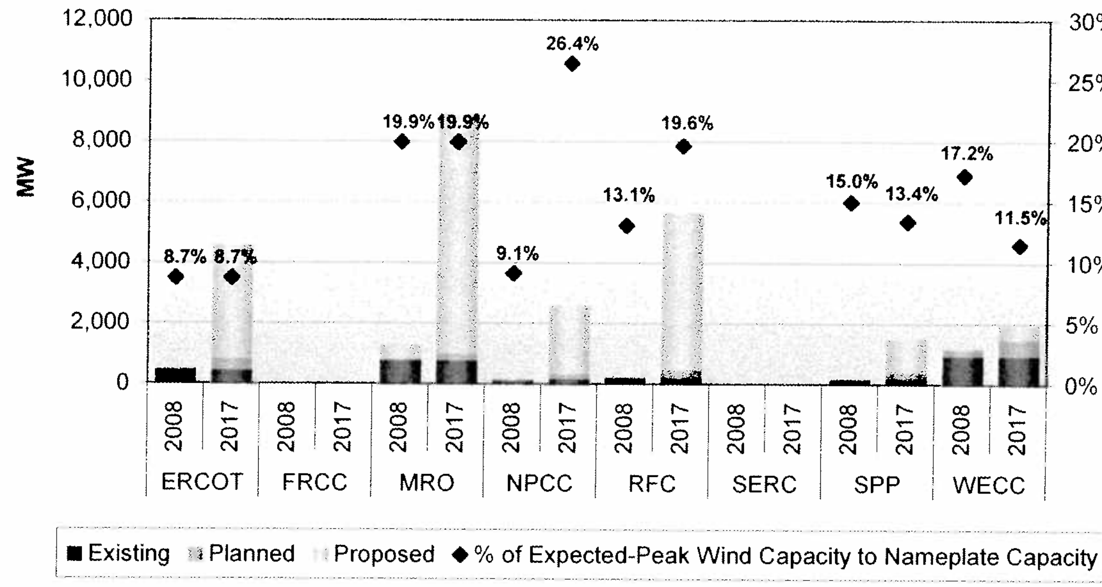
While other renewable resources are beginning to appear in forecasts (800 MW of Existing-Certain and 280 MW of Planned solar capacity resources were reported in WECC), wind generation has become the primary reported focus of renewable resource development in North America.

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

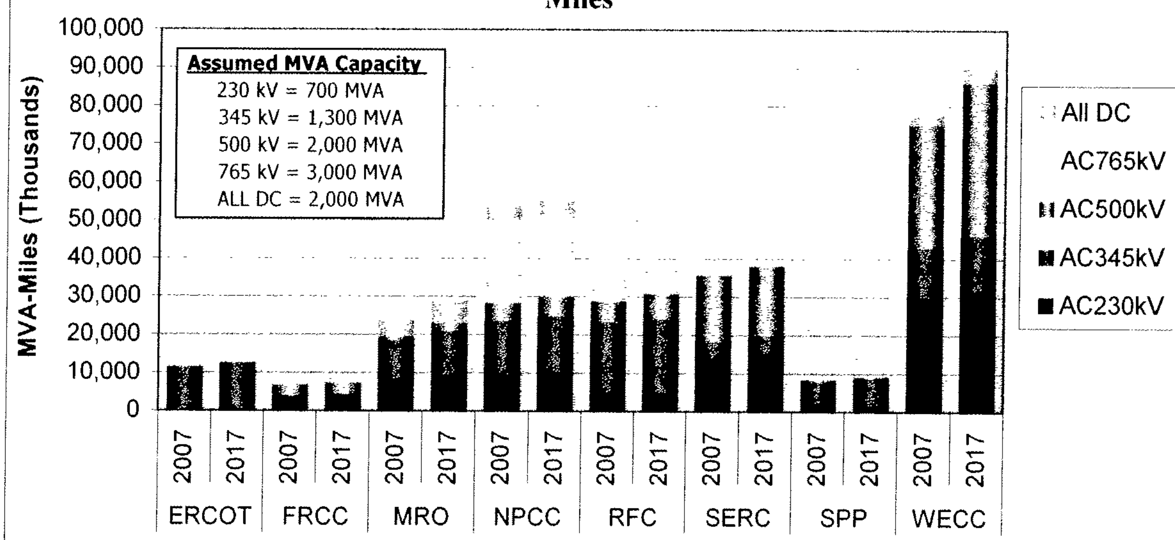
[24] NERC does not collect transmission additions with the same granularity as supply-side resources. This comparison assumes the mileage reported includes Proposed transmission additions which is compared to Proposed Capacity additions.

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)

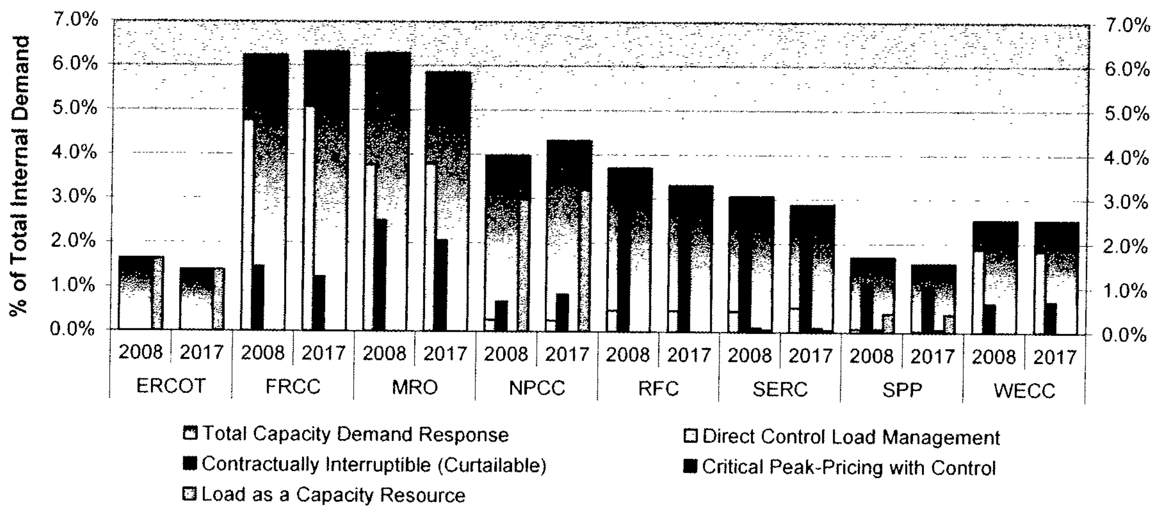
[28] NERC expects to issue a special report in December 2008 on the reliability requirements for integrating variable generation into the bulk power system.

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.

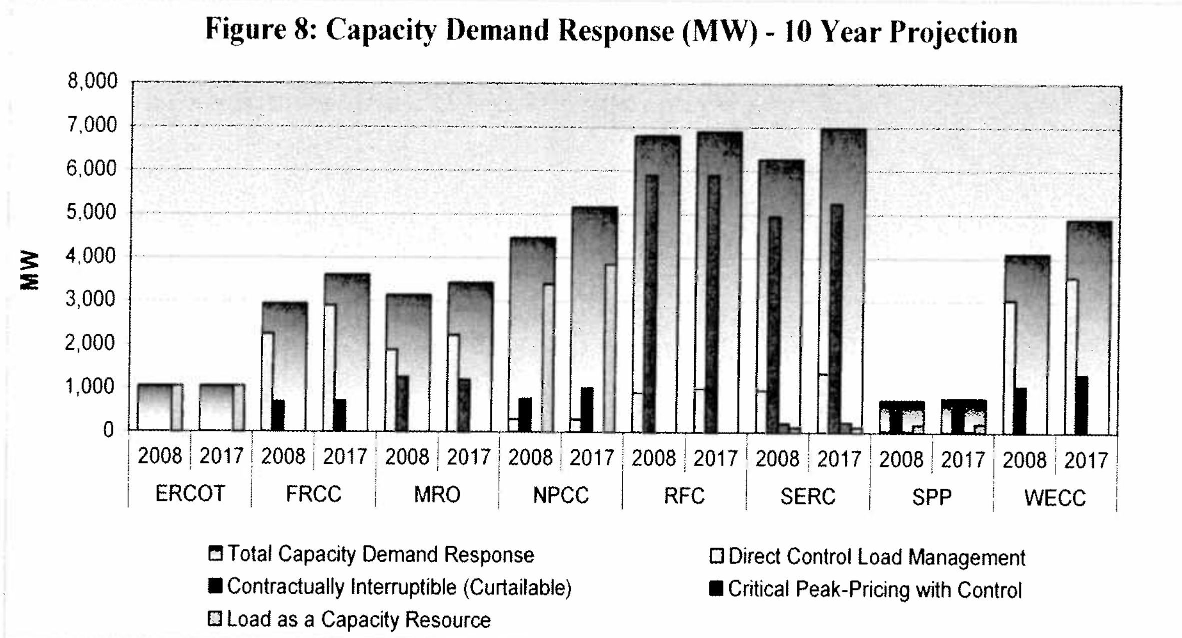
Significant increases in demand response programs over the next ten years are projected to reduce growth in demand and provide ancillary services across North America. As shown in Figure 7, Capacity Demand Response,[29] as a percentage of demand, is increasing in FRCC (over 6% of demand) and NPCC (up 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

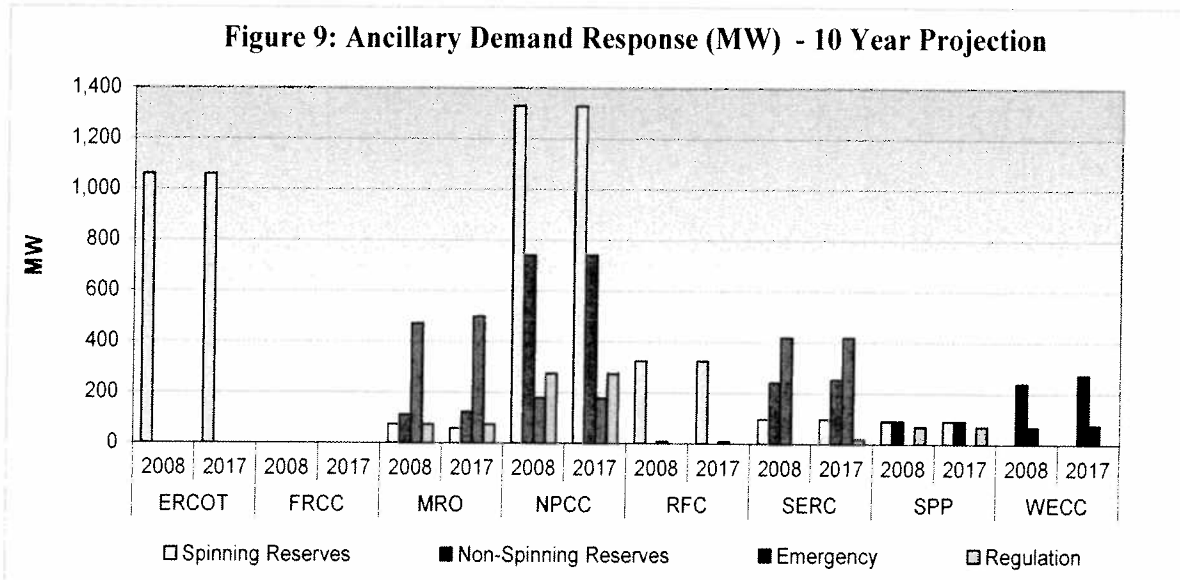


The total NERC-wide Capacity Demand Response for summer peak demand reduction grows from 29,000 MW in the summer of 2008 to 32,500 MW in the summer of 2017. Figure 8 shows the projected increases in dispatchable demand response by region.

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



The total NERC-wide demand response used for Ancillary Demand Response during the summer peak remains about constant at 4,400 MW. NERC regional comparison is shown in Figure 9.



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.

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[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 pa rt 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

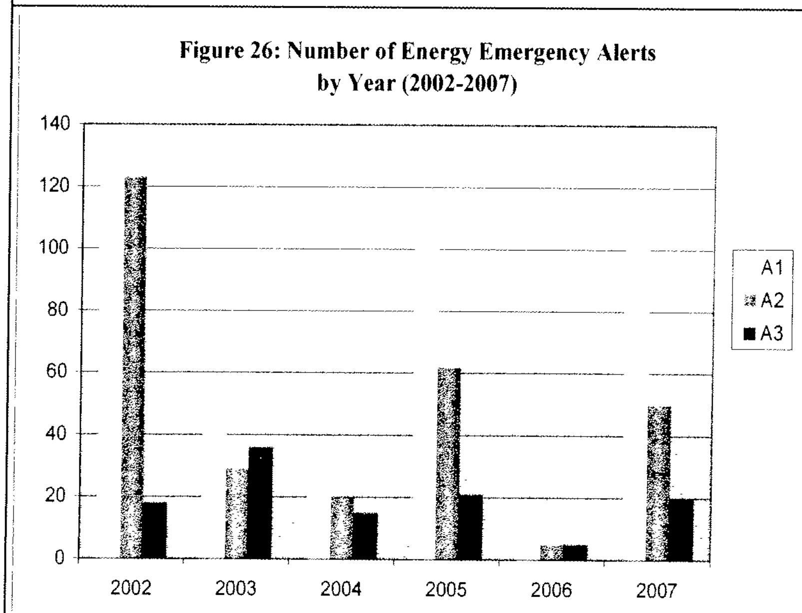
5. Bulk Power System Adequacy Trends Emphasize Maintenance, Tools and Training

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.

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

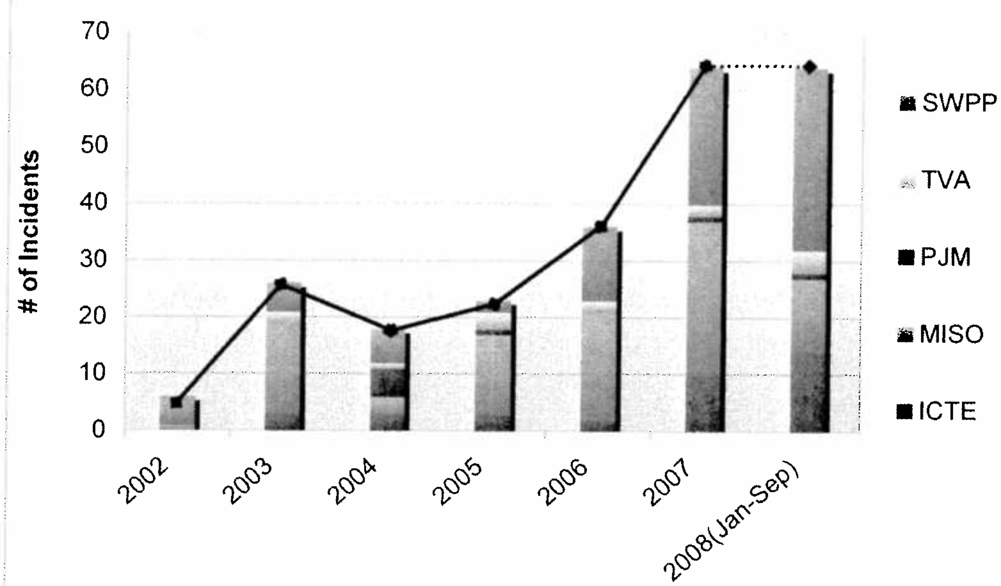
[34] http://en.wikipedia.org/wiki/Eastern_Interconnection

[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).

[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.