NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

December 2, 2011

VIA ELECTRONIC FILING

Re: North American Electric Reliability Corporation, *2011 Long-Term Reliability Assessment*, Docket No. RC11-_-000

The North American Electric reliability Corporation (NERC) submits solely as an informational filing the *2011 Long-Term Reliability* Assessment; a report prepared by NERC, released on November 28, 2011.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2011 Long-Term Reliability Assessment

November 2011

RELIABILITY | ACCOUNTABILITY

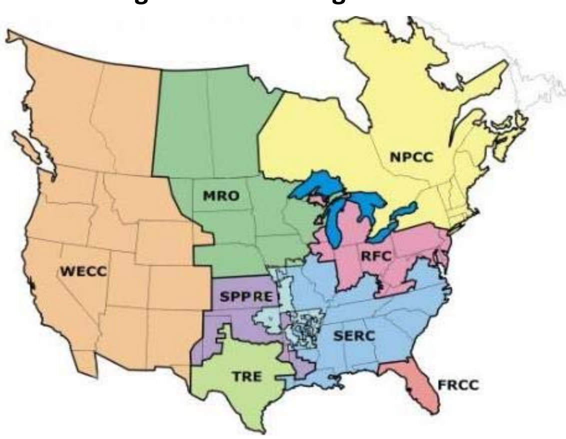
Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.[1,2] NERC operates under similar obligations in many Canadian provinces as well as a portion of Baja California Norte, México.

NERC Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses reliability annually via a 10-year assessment and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[3]

Figure A: NERC Regional Entities



Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://thomas.loc.gov/cgi-bin/bdquery/z?d109:HR00006:@@@L&summ2=m&.

[2] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[3] 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. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable.

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown in the map (Figure A) and corresponding table (Table A). The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.

About this Report

This assessment provides an independent view of the long-term reliability for the North American bulk power system,[4] while identifying trends, emerging issues, and potential concerns. Additional insight will be offered regarding seasonal resource adequacy and operating reliability, and an overview of projected electricity demand growth, Assessment Area highlights, and Assessment Area self-assessments.

NERC's primary objective in providing this assessment is to identify areas of concern regarding the reliability of the North American bulk power system and to make recommendations for their remedy as needed. The assessment process enables bulk power system users, owners, and operators to systematically document their operational preparations and exchange vital system reliability information. This assessment is prepared by NERC in its capacity as the Electric Reliability Organization.[5] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[6] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

Report Preparation

NERC prepared the *2011 Long-Term Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The Resources Issue Subcommittee (RIS) and Transmission Issues Subcommittee (TIS) also contributed to the report by providing input on emerging issues. The report is based on data and information submitted by each of the eight Regional Entities in May 2011 and updated, as required, throughout the drafting process. Any other data sources consulted by NERC staff in the preparation of this document are identified within the report.

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

[4] Bulk power system reliability, as defined in the *How NERC Defines Bulk Power System Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

[5] 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."

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

are fully convinced that each self-assessment is accurate, thorough, and complete. Data is further reviewed to ensure that transfers into or between two areas are validated.

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

In the *2011 Long-Term Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[7]

- Supply and demand projections are based on industry forecasts submitted in May 2011. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting timeframe (May – September).
- Peak demand and Planning Reserve Margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned; planned outages take place as scheduled; retirements are scheduled as proposed
- Demand reductions expected from dispatchable and controllable Demand Response programs will yield the forecast results, if they are called on.
- Other peak Demand-Side Management programs, such as Energy Efficiency and price-responsive Demand Response, are reflected in the forecasts of Total Internal Demand.

NERC Assessment Areas

NERC has historically collected and provided data and information for all assessments based on Regional Entity boundaries. These boundaries were established through consideration of the respective membership of each Regional Entity, comprising of both Planning Coordinators and Load Serving Entities (LSEs). There are approximately eighty NERC Planning Coordinators,[8] ten of which are Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs) which encompass a large portion of North America. Four of these Planning Coordinators operate in multiple Regional Entities listed below:

- American Transmission Co., LLC:[9] MRO, RFC
- Midwest Independent Transmission System Operator, Inc: MRO, RFC, SERC

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

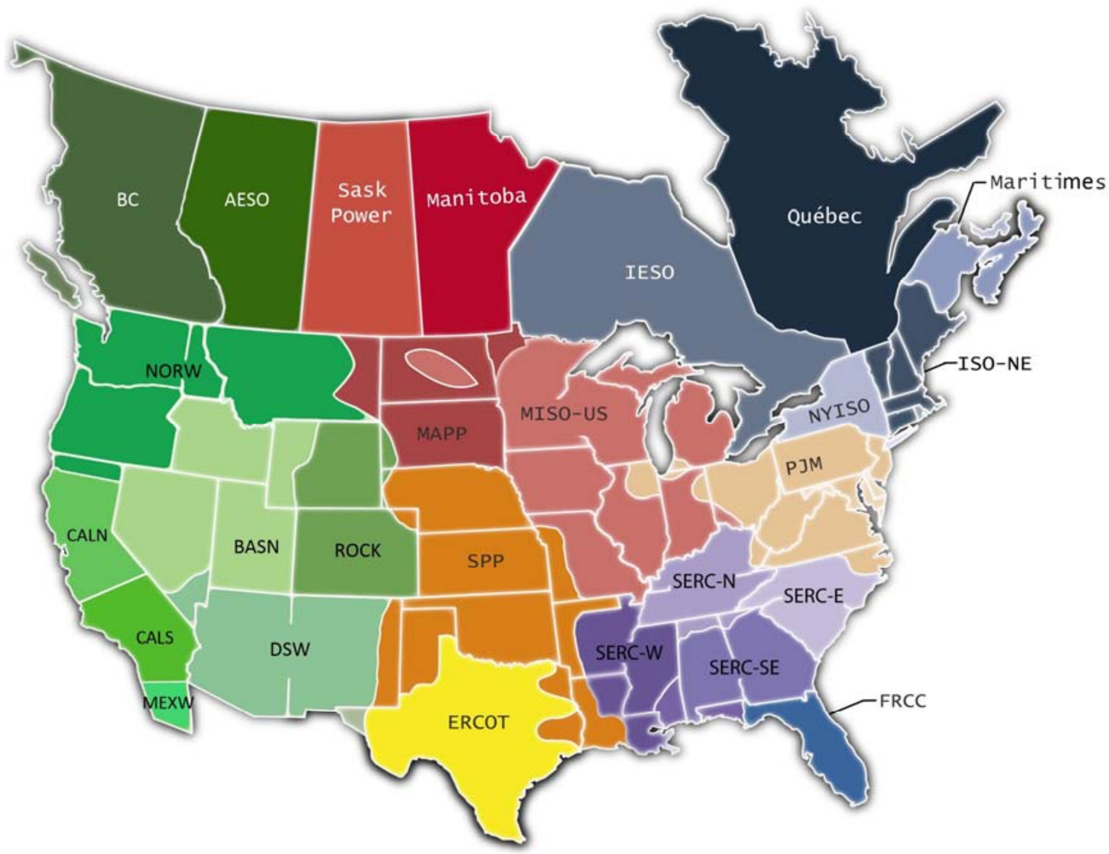
[8] http://www.nerc.com/files/Function%20Change%20Activity%20Report%20By%20Entity%20Name20110829.pdf.

[9] The America Transmission Co., LLC does not provide generation/load projection data for reliability assessments and, coordinates its transmission resources with other Planning Coordinators.

- PJM Interconnection, LLC: RFC, SERC
- Southwest Power Pool: MRO, SPP

Historically, these four Planning Coordinators have provided capacity and load data to multiple Regional Entities. Consequently, this data has been artificially divided based on political boundaries that failed to accurately reflect the planning and operational properties of the bulk power system. This approach has reduced the accuracy of the resource and demand balance in these four Planning Coordinators that span over multiple Regional Entity boundaries. Taking these considerations into account, NERC has instituted the following Assessment Areas (Figure B) for this long-term assessment.

Figure B: 2011 Long-Term Assessment Areas[10]



ISO/RTO boundaries are subject to change over time due to consolidation or alterations in resource planning and acquisition arrangements. NERC's Assessment Area boundaries will adjust as necessary and any changes will be reflected and explained in future assessments.

Note: the term "Assessment Areas" will be used throughout this report, often in place of the term "Regions," or "Subregions."

[10] WECC subregions are divided differently for seasonal (four subregions) and long-term assessments (nine subregions).

How to Read this Report

This report is generally compiled with three major parts:

NERC Reliability Assessment

- Determine major industry challenges and considerations
- Evaluate industry preparations in place to meet projections and maintain reliability
- Identify trends in demand, supply, and Reserve Margins
- Focus the industry, policy makers, and the general public's attention on significant issues facing bulk power system reliability
- Make recommendations based on an independent NERC reliability assessment process

Emerging Reliability Issues

- Identify industry issues that may pose reliability issues in the future that may not be included in the current reference case
- Perform a risk assessment for each issue to determine potential impacts
- Assess reliability issues using scenario analysis
- Regional Reliability Assessment

NERC Region Highlights

- Detailed reliability assessment for each Assessment Area
- Focus on region-specific issues identified through industry data and emerging issues
- Identify regional planning processes and methods used to ensure reliability

Additional information and data tables are located in the Appendices.

Errata

11/29/11 v2011.1

Potential Impacts of Future Environmental Regulations – Figure 59

Updated the CSAPR differences between Moderate Case and Strict Case.

Potential Impacts of Future Environmental Regulations - Pg. 144

Values in sentence adjusted to reflect report results

The total economically vulnerable capacity could reach 36 GW under the Moderate Case, and up to 59 GW in the Strict Case (Table 34).

Table of Contents

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NERC Reliability Assessment

Introduction and Executive Summary

In preparing this assessment, NERC has evaluated the key reliability indicators, including peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other influential or regulatory issues that may impact the reliability of the bulk power system. For the *2011 Long-Term Reliability Assessment*, a significant effort was made to further identify the impacts to bulk power system reliability due to significant potential generation retirements triggered by environmental regulations.

The electric industry has prepared plans for the 2011 through 2021 assessment period in an effort to provide reliable electric service across North America. However, in some Assessment Areas, issues exist that could impact the implementation of these current plans. Over the next ten-years, the electric industry will face a number of significant emerging reliability issues. The confluence of these uses will drive a transformational change for the industry, potentially resulting in a dramatically different resource mix, a new market for emissions trading, a need for enhanced modeling, and a new risk framework built to address growing critical infrastructure and protection concerns—both physical and cyber. Each of these elements of change is critically interdependent and industry action must be closely coordinated to ensure reliability. This report will identify key issues and risks to bulk power system, included below (Figure 1).

Table 1: Report Highlights

RESERVE MARGINS A decrease in projected Future and Conceptual generation resources lead to declining Planning Reserve Margins in some areas—resource adequacy in Texas shows signs of concern; however, most areas appear to have adequate resource plans to meet projected peak demands.	**ENVIRONMENTAL REGULATIONS** Existing and proposed environmental regulations in the U.S. may significantly affect bulk power system reliability depending on the scope and timing of the rule implementation and the mechanisms in place to preserve reliability.
GAS-ELECTRIC INTERDEPENDENCY The growing dependence on natural gas as a primary fuel source of on-peak capacity must be considered in planning; operational measures must be in place to minimize interdependency risks particularly during off-peak periods as more gas-fired generation is expected to provide base-load functions.	**VARIABLE GENERATION** Significant growth in wind and solar generation continues to be projected, surpassing the NERC-wide on-peak capacity forecasts of all other types of generations. Tools, training, and transmission remain key to successful planning and operations.
DEMAND-SIDE MANAGEMENT Significant increases in Demand-Side Management continue to offset future resource needs, while dispatchable and controllable types expand flexibility for operators.	**TRANSMISSION** Transmission growth is responding to increased plans for integrating and delivering new resources (*i.e.,* renewables); constructed transmission is on pace with projections.

The electric industry continues to expand the use of a wide variety of generation resources and Demand-Side Management (DSM) programs to maintain a reliable supply portfolio to meet projected peak demand in North America. On the demand side, the electric industry is implementing Energy Efficiency, Conservation, and Demand Response programs to effectively manage both peak demand and overall energy use. Supply projections rely on the upgrading of existing units, addition of new resources (mostly wind and gas generation), and the planned purchase of electricity from neighboring systems.

One of the greatest risks identified by the NERC Planning Committee (high likelihood, high consequence), is the potential impacts of future environmental regulations. Because of the inherent uncertainties associated with understanding what the actual impacts will be, projections in this report do not necessarily take into account all potential retirements that may be triggered by the finalizations of environmental regulations. While some environmental regulations have been finalized (*i.e.,* Cross-State Air Pollution Rule (CSAPR),[11] others such as the Cooling Water Intake Structures—CWA §316(b)[12] and the Air Toxics Standards for Utilities[13] have not yet been finalized. The latter two proposed rules have been identified as having a potentially higher impact for electric reliability, causing significant generator retirements and/or a tight compliance schedule. Depending on the scope and timing of these rules, mechanisms should be in place to preserve reliability; however, the future state of reliability is still undetermined. Because industry plans for accommodating these rules are not yet finalized, NERC must and has identified the potential impact based on a modeling approach that was used in 2010 to identify potential resource adequacy issues.[14] The results of the NERC study are included in this report and should be used to supplement the current projections of resource adequacy. Inherent risks associated with the uncertainty of existing and future resources must be thoroughly understood by industry participants, policymakers, and regulators in order to ensure the continued delivery of reliable power throughout North America. NERC is strongly focused on the recommendations presented for the industry and Federal and state regulators—as well as those for NERC. While the capacity impacts resulting from potentially early retirements are informative and provide a basis for assessment, sufficient compliance timelines and certainty in industry requirements should remain at the forefront of the discussion on reliability impacts.

In addition to the regulatory drivers triggering an unprecedented resource-mix change, societal and political pressures continue to prompt the industry to integrate more renewable generation into its resource portfolio. With emerging requirements for renewable portfolio standards (RPS), potential limits on greenhouse gasses, and increased Demand Response, Energy Efficiency and conservation measures, environmental issues have moved from a preparation phase to an implementation phase for bulk power system planners and operators.

[11] CSAPR Website: http://www.epa.gov/airtransport/.

[12] Cooling Water Intake Structures—CWA §316(b) Website: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

[13] Air Toxics Standards for Utilities: http://www.epa.gov/ttn/atw/utility/utilitypg.html.

[14] 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf.

While the key highlights in this report are presented independently, they are cross-cutting and the interdependencies between these issues present unique challenges to the electric power industry. Growth in flexible resources, such as Demand Response and quick-start natural gas power generators, and increased transmission plans to integrate renewable resources distant from load centers are encouraging trends. However, fundamental changes to planning and operated strategies must conform to consider evolving risks such as gas and electric interdependencies, increased uncertainty from variable generation consuming less predictable fuel sources, and new vectors of penetration for emerging cyber and physical security threats. The confluence of these risks must be strategically managed, monitored, and mitigated in order to preserve the future reliability of the bulk power system.

Progress Since 2010

In the *2010 Long-Term Reliability Assessment*,[15] NERC identified four key findings that could affect long-term reliability, unless actions were taken by the electric industry. NERC's key findings in 2010 were based on observations and analyses of supply and demand projections submitted by the Regional Entities, NERC staff independent assessment, and other stakeholder input and comments.

The magnitude of these issues necessitates complex planning and effective strategies whose effects may not be realized for several years. As shown in Table 2, while much progress has been made since last year, continued action is still needed on all of the issues identified in last year's report to ensure a reliable bulk power system for the future. NERC continues to monitor and assess these issues based on industry progress through its annual reliability assessments, as well as, through any special reliability assessments that may be needed as determined by the NERC Planning Committee.

Table 2: Progress on 2010 Key Findings

2010 Key Finding	*Economic Recession, Demand-Side Management Lead to Decreased Demand, Higher Reserve Margins*	*Unprecedented Fuel-Mix Change; Increases in Gas, Wind, Solar, and Nuclear Generation*	*Transmission Increases According to Plans; Integrating Projected Renewable Generation*	*Cross-Industry Communication and Coodination is Key to Successful Planning and Operations*
Progress in 2011	Recession effects dimished; 2011 demand forecast similar to 2010 Lowest growth rate on record	Issued 4 reports variable generation Phase I report on Gas-Electric Interdependency	Trend continues in 2011 2011 Key Highlight Progress shown in the last five years	Event Analysis and Lessons Learned issued NERC Alerts mature
2011 Status	Planning Reserve Margins decrease in some areas Demand forecast uncertainty assessed	Phase II Gas-Electric Interdependencies Assess impacts of environ. regulations 2011 Key Highlight	Transmission additions were higher than average from 2006 to 2010	Gas and electric industry communication and coordination continues to be studied

[15] *2010 Long-Term Reliability Assessment:* http://www.nerc.com/files/2010_LTRA_v2-.pdf

Resource Adequacy Assessment

NERC assesses resource adequacy by evaluating each Assessment Area's Planning Reserve Margins—a deterministic method based on traditional capacity planning.[16] For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability during the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections and cause the NERC reference case to change, adding considerable uncertainty not only in the long-term, but in the short-term as well. Where markets exist, signals for new capacity must be effective for planning purposes, reflecting the lead times necessary to construct new generation as well as any associated transmission. In a transition to reduce environmental impacts caused by uncontrolled, higher-emission generating plants, regulatory compliance deadlines could conflict with existing planning and approval processes—both regional and interregional.

A unique characteristic of electricity supply is the long lead time for developing and constructing transmission, which is instrumental in integrating new resources into the bulk power system. Although generating plant in-service lead times have been significantly reduced (excluding environmental permitting processes), transmission planning and approval necessary to integration these new resources have not experienced a similar lead time reduction. While transmission needs are identified and coordinated by transmission planners and Planning Authorities through reliability studies (e.g., loadflow, stability, voltage security), NERC assesses resource adequacy by evaluating area Planning Reserve Margins —a deterministic method based on traditional capacity planning.

Supply and Planning Reserve Margin projections in this assessment do not necessarily take into account all retirements of generators due to potential environmental regulations. While some generators have already announced and planned for retirement, the majority of vulnerable generation resources have not finalized plans to comply with existing and pending environmental regulations. A significant amount of generation retirements can have a considerable impact to Planning Reserve Margins, if new resources and associated transmission cannot be constructed or acquired before the compliance deadlines. The results would drive on-peak Planning Reserve Margins lower than forecasted in this assessment.[17]

Planning Reserve Margins for several Assessment Areas, which include all Anticipated Resources and Adjusted Potential Resources,[18] fall below the NERC Reference Margin Level[19] by 2021 or sooner (Figure 1 and Figure 2) These Assessment Areas include ERCOT, MRO-MAPP, and NPCC-New England (ISO-NE). Additionally, MRO-Manitoba, NPCC-Ontario (IESO), PJM, SERC-W, and WECC-AESO are unable to meet

[16] Planning Reserve Margins in this report represent margins calculated for planning purposes (Planning Reserve Margins) not operational Reserve Margins which reflect real-time operating conditions. See *Estimated Demand, Resources, and Reserve Margins* for specific values.

[17] This issue is further discussed in the Emerging Issues section with a detailed analysis in the *EPA Impact Assessment* section.

[18] Adjusted Potential Resources generally include capacity from Existing, Future, and an adjusted amount of Conceptual resources. Please see the *Terms Used in this Report* section for more detailed information.

[19] Each Assessment Area may have its own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If a requirement is provided to NERC, that requirement is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.

the NERC Reference Margin Level with Anticipated Resources alone. Based on this year's forecast, additional resources may be needed in these areas in order to maintain sufficient reserve capacity in the long-term horizon. The remaining Assessment Areas are able to meet the NERC Reference Margin with Anticipated Resources alone through 2021.

Figure 1: NERC-Wide Planning Reserve Margins

Year when each Assessment Area's projected planning Reserve Margins (RM) drop below the NERC Reference Margin Level

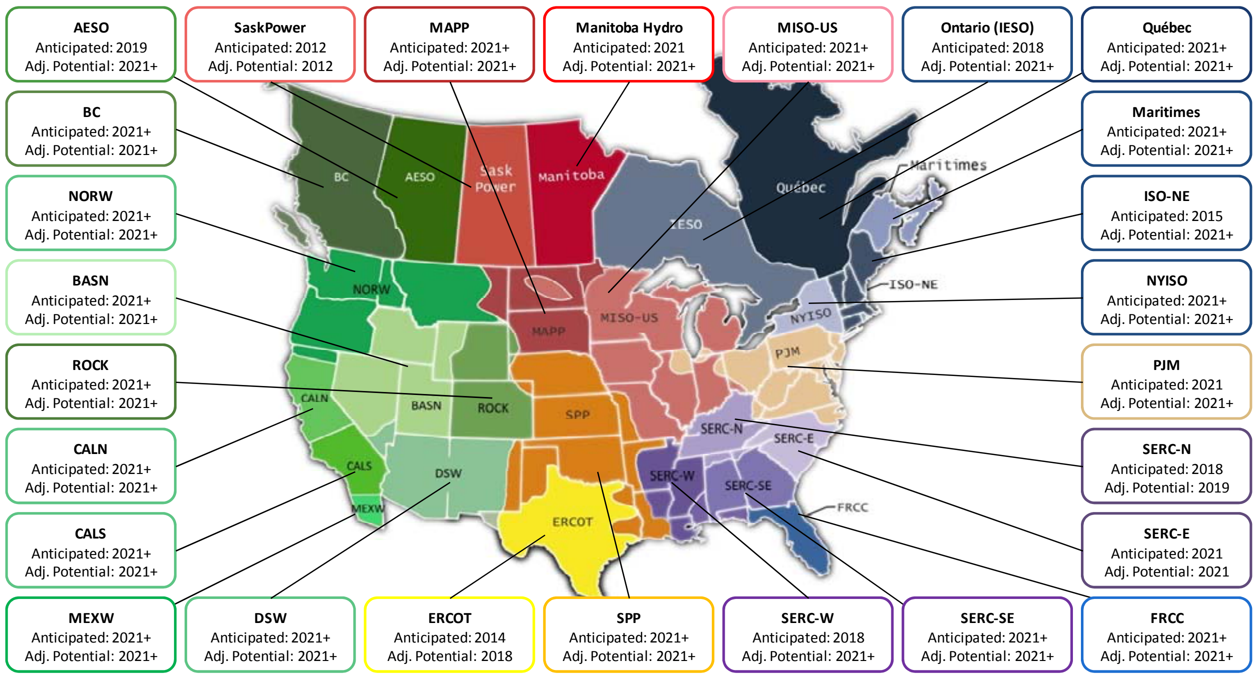
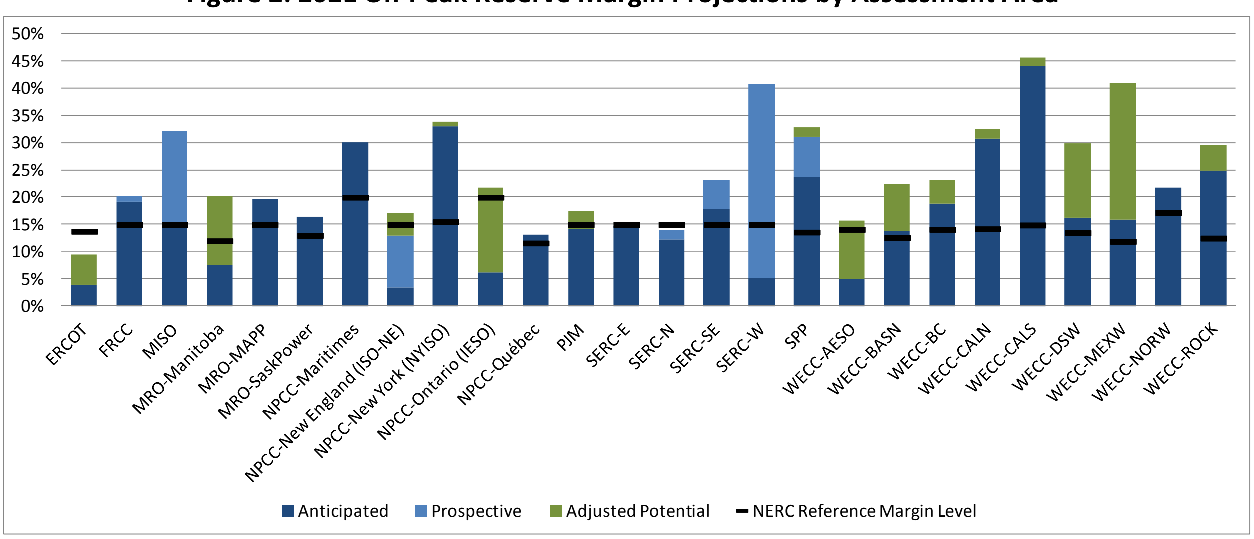


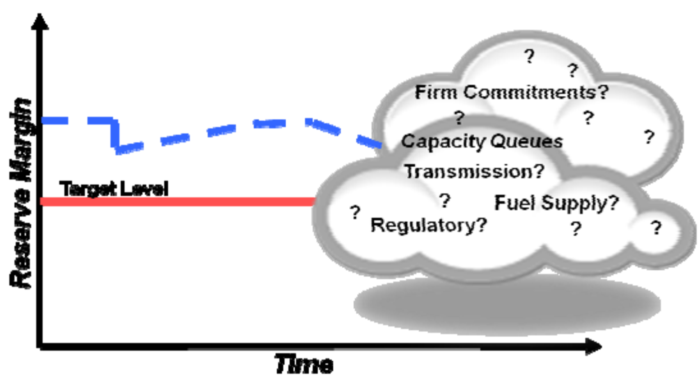
Figure 2: 2021 On-Peak Reserve Margin Projections by Assessment Area



In ERCOT, the NERC Reference Margin Level is not projected to be met by 2013, raising significant concerns of resource adequacy. Because these issues are reflected in the relatively short-term and the isolated nature of the Texas Interconnection, ERCOT may face challenges building or acquiring new resources over the next two years. Further, less resources were available in ERCOT during 2011 than was forecast in the *2010 Long-Term Reliability Assessment,* a difference of about 700 MW.[20] Stated again, more generation may be retired, depending on how the finalized environmental regulations are implemented. Additional retired generation will compound ERCOT's projected capacity deficit, worsening reliability issues in the Region.[21,22]

In general, long-term planning (beyond five years) is inherently uncertain due to, among other things, varying market practices and regulatory conditions, such as environmental regulations (Figure 3). In these areas where Anticipated Resources fall short of meeting the NERC Reference Margin Level, Adjusted Potential Resources must be accelerated as they will be needed. However, Adjusted Potential Resources carry a higher degree of uncertainty because these resources are in the early stages of development. Therefore, considerable progress in resource development must be made in order to bring these resources online. Engineering studies, siting and permitting, and construction represent the activities required before these resources can have reasonable expectation to be in-service. Furthermore, both peak demand and supply resources are expected to have similar growth over the next 10-years (approximately 100,000 MW each). Should peak demand grow faster than projected, additional *Conceptual* resources should be developed as they likely will be needed to maintain resource adequacy.

Figure 3: Uncertainties of Planning Reserve Margins



The Planning Reserve Margin projection for the United States is lower than projected in 2010.[23] With the impacts from the recent economic recession directly linked to electricity use, the industry, in the past two years, has observed higher Planning Reserve Margin projections in the latter years of the assessment period. While the 2012 Anticipated Planning Reserve Margin is slightly higher than last year's projection, the long-term projection for 2019 is less than last year's projection. As a whole, this

[20] *2010 Long-Term Reliability Assessment*: http://www.nerc.com/files/2010_LTRA_v2-.pdf.

[21] ERCOT CSAPR Assessment: http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

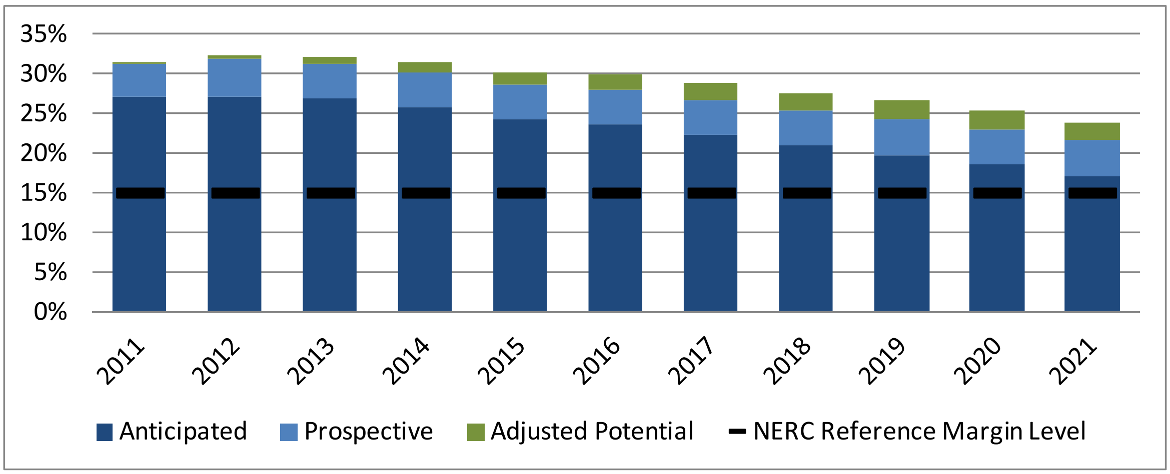
[22] See the *EPA Impact Assessment* section for potential resource adequacy implications.

[23] The North American bulk power system does not have the capability to transmit power across its entire expanse; therefore, a North American, United States, or Canadian aggregated Planning Reserve Margin is only a general indicator. While this value provides a comparison of projected peak demand versus projected capacity, it is not representative of resource adequacy within all areas of North America.

decrease is due to less capacity being projected in the long-term. When compared to the 2010 Long-Term Reliability Assessment's 2019 forecast, the 2011 forecast is approximately 24,000 MW less.[24] Negative forecasts in coal-fired generation along with increased demand projections are the primary drivers of Planning Reserve Margin reductions.

During this assessment period, Planning Reserve Margin projections in the U.S. remain above the 15 percent reference level with a general downward trend(Figure 4). This is true for all calculated Planning Reserve Margins (Anticipated, Prospective, and Adjusted Potential). Again, this decrease may be reflecting the industry's uncertainty in projected plans for replacement capacity due to retiring generation and overall cautiousness of generation developers.

Figure 4: U.S. On-Peak Summer Reserve Margins

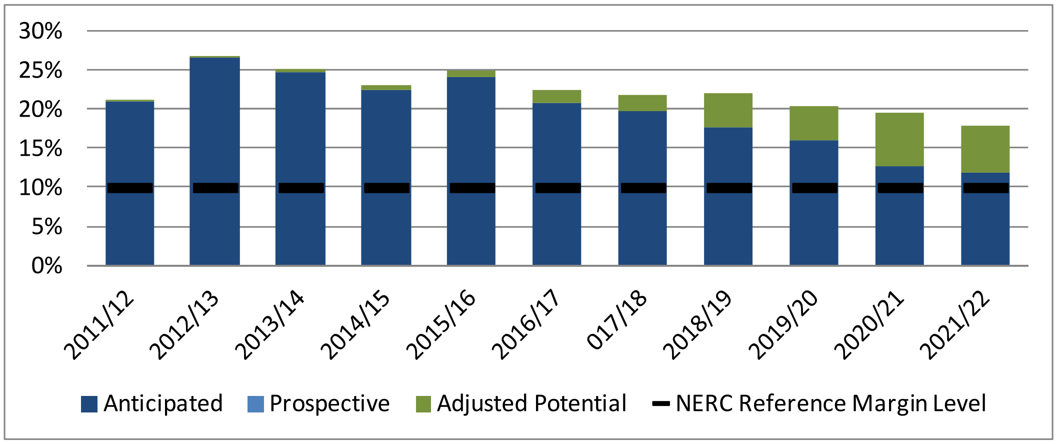


However, the projected decrease in Planning Reserve Margins in the latter years of the 10-year forecasts is typical. The early years provide more certainty since new generation is either in-service or under construction with firm commitments. In the later years, there is less certainty about the resources that will be needed to meet peak demand. Declining Planning Reserve Margins are inherent in a conventional forecast (assuming load growth) and do not necessarily indicate a trend of a degrading resource adequacy. Rather, they are an indication of the potential need for additional resources. In addition, key observations can be made about the Planning Reserve Margin forecast, such as the rate the Planning Reserve Margin changes through the assessment period, identification of Planning Reserve Margins that are approaching or below a target requirement, and comparisons from year-to-year forecasts. While resource planners are able to forecast the need for resources, the type of resource that will actually be built or acquired to fill the need is less certain. For example, in the northeast U.S. markets, with a 3- to 5-year forward capacity market, firm commitments are not made for the long-term horizon covered in this report.

[24] The 2010 Long-Term Reliability Assessment's 2019 summer peak forecast of Anticipated Capacity Resources were projected at 1,119,349 MW, compared to the current 2011 Long-Term Reliability Assessment's 2019 summer peak forecast of Anticipated Capacity Resources of 1,143,722 MW.

The downward trend is also projected in Canada, but to a much lesser extent (Figure 5). Despite relatively significant demand growth in Canada and the retirement of coal-fired generation, mainly in Ontario, future supply projections appear to be in-line with demand trends. For Canada, the long-term Planning Reserve Margin projections are well above the NERC Reference Margin Level of 10 percent, which is applied to Canada due to the nation's abundance of hydro-powered generation.

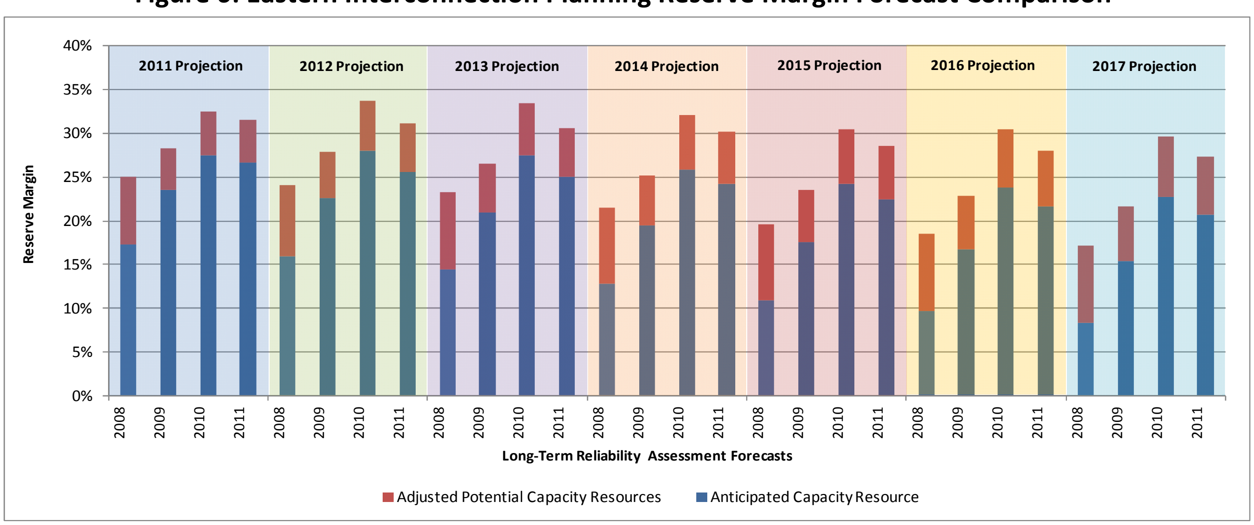
Figure 5: Canada On-Peak Winter Reserve Margins



Comparisons of interconnection projections using data from the *2008, 2009, 2010 and 2011 Long-Term Reliability Assessments* are shown below (Figure 6 through Figure 9). The 10-year projections from each assessment share a period of overlap from 2011 through 2017. The projection for the common years of each forecast offers a year-to-year comparison of Planning Reserve Margin forecasts.

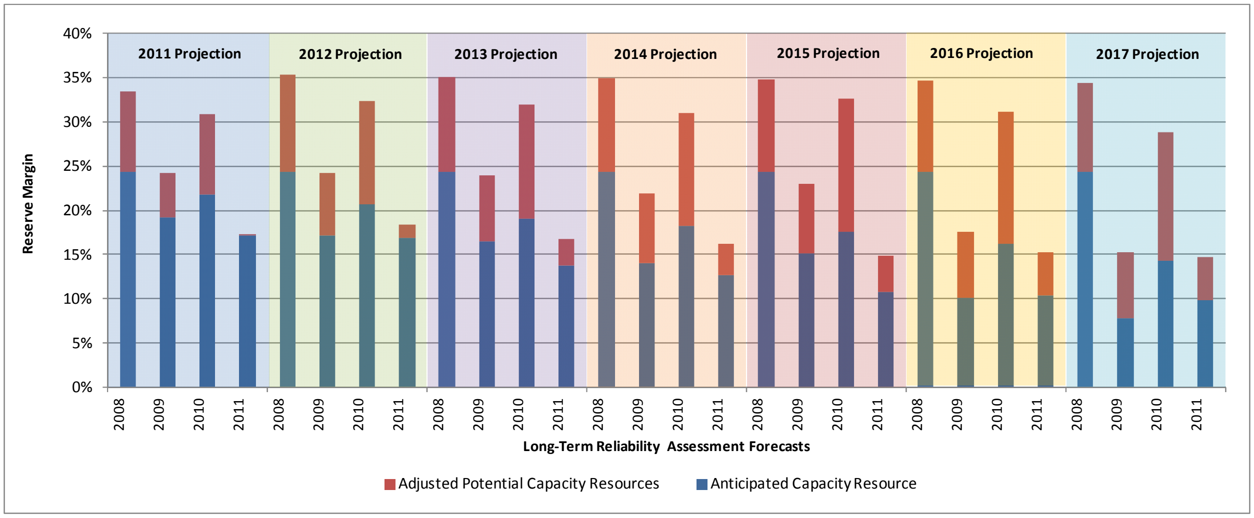
In the Eastern Interconnection, Planning Reserve Margins were on the rise between 2008 and 2010 (Figure 6). However, the 2011 forecast shows a decrease when compared to last year's forecast. Since the demand forecast in line with last year's forecast, the decrease indicates a decreased supply projection. While the 2011 forecast stays above 20 percent and does not indicate major supply issues, this trend should continue to be monitored to identify any adequacy bottlenecks.

Figure 6: Eastern Interconnection Planning Reserve Margin Forecast Comparison



The Planning Reserve Margin projection in the Texas Interconnection (i.e., ERCOT), has significantly decreased since last year—more than 15 percentage points across all projection years, and almost 20 percentage points when compared to the 2008 forecast in the later year projections (Figure 7). Because of the relatively isolated area served in the Texas Interconnection and inherent constraints in building new capacity, this trend needs to be closely monitored. More resources will be needed in Texas to support projected peak demand, potentially significant generator retirements, and an increased need for reserve capacity to support variable generation.

Figure 7: Texas Interconnection Planning Reserve Margin Forecast Comparison



In the Western and Québec Interconnections, Planning Reserve Margins have generally been flat since 2008—confirming future supplies are projected to keep up with demand growth (Figure 8 and Figure 9).

Figure 8: Western Interconnection Planning Reserve Margin Forecast Comparison

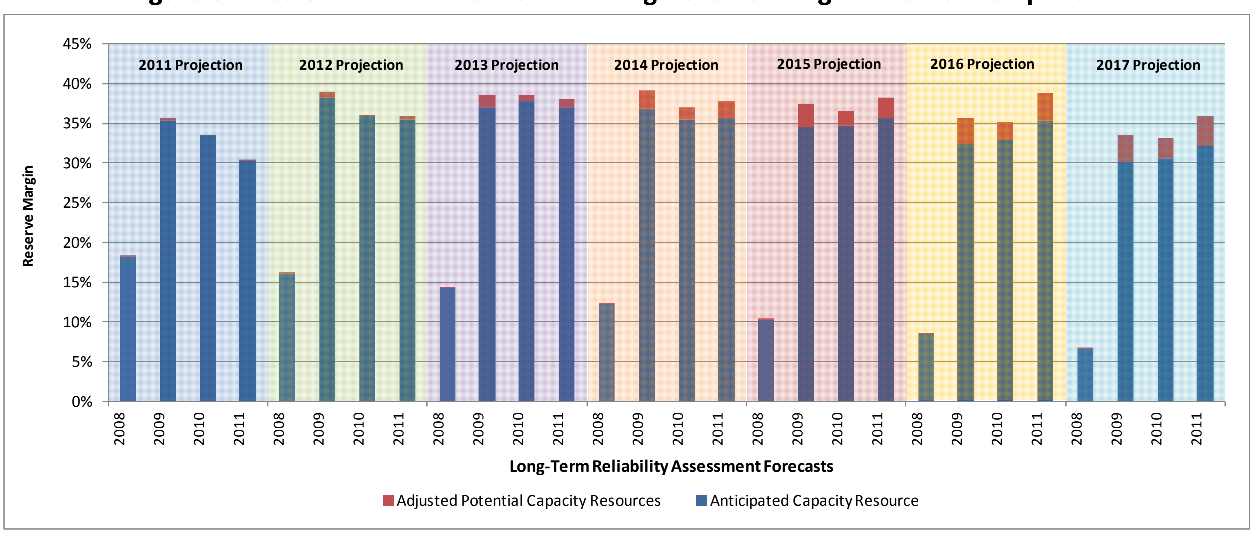
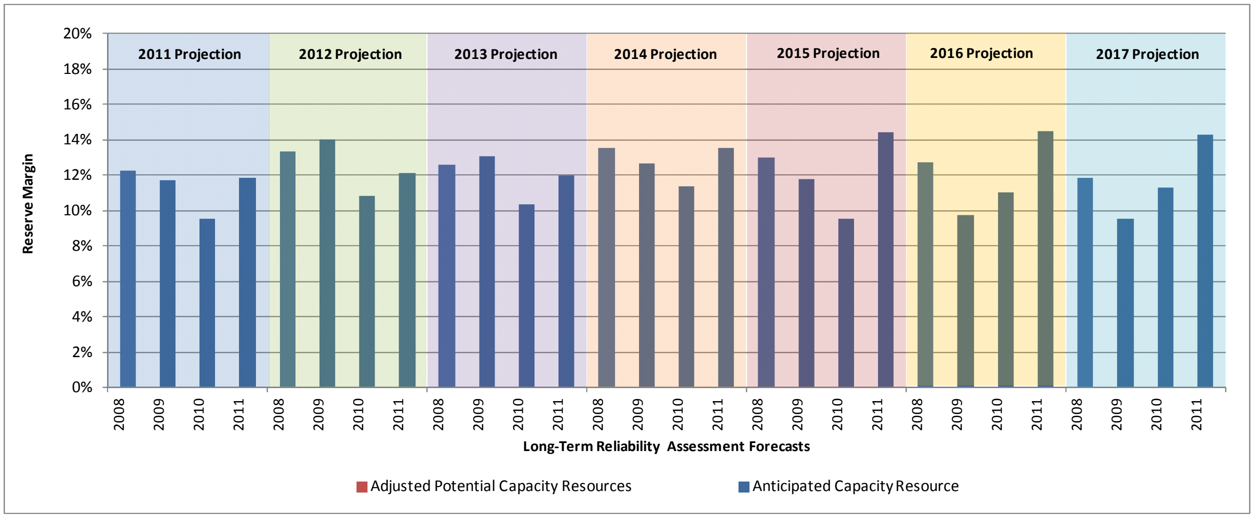


Figure 9: Québec Interconnection Planning Reserve Margin Forecast Comparison



KEY FINDINGS - RESERVE MARGINS

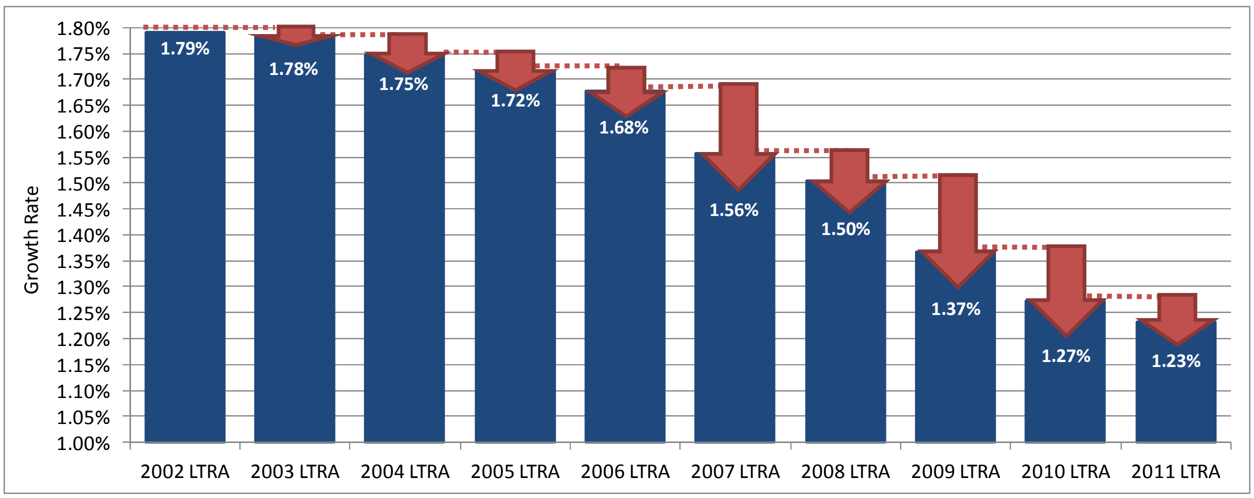
A decrease in projected Future and Conceptual generation resources lead to declining Planning Reserve Margins in some areas—resource adequacy in Texas shows signs of concern; however, majority of areas appear to have adequate resource plans to meet projected peak demands.

Peak Demand Projections

The recent economic recession significantly reduced electricity demand projections in the short-term and created great uncertainty for long-term projections across North America. Although the recession officially ended half-way through 2009, the recovery to pre-recession economic growth has been hindered due to lingering high unemployment rates and continued signs of stress throughout the global financial system. In July of this year, the Board of Governors of the Federal Reserve System reported the economic outlook for the United States includes a sluggish but continued recovery.[25] Similarly, the Canadian Chamber of Commerce (La Chambre De Commerce Du Canada) expects "modest" economic short-term expansion.[26]

NERC's electricity demand projections for North America align with these economic outlooks, reinforcing the link between economic conditions and electricity demand. Although the demand characteristics differ based on each NERC Assessment Area, overall electricity demand is still forecasted to grow at a slower rate compared to prior years (Figure 10). In fact, the 2011 demand forecast average annual compound growth rate is the lowest 10-year growth rate recorded by NERC's *Long-Term Reliability Assessments*, which started in 1967.

Figure 10: Comparison of Annual Average Growth Rates for NERC-wide Summer Peak Demand



The 2011 summer peak Total Internal Demand forecast for the United States is more aligned with last year's projections, indicating the beginning of some recovery activity after two years of decline (Figure 11). The 11.7 GW (or 1.3 percent) growth projected for 2011 in last year's assessment is in line with this year's projection—similar endpoints are observed as well. Projected average annual growth rates are still declining, but at a significantly slower rate than observed in prior years.

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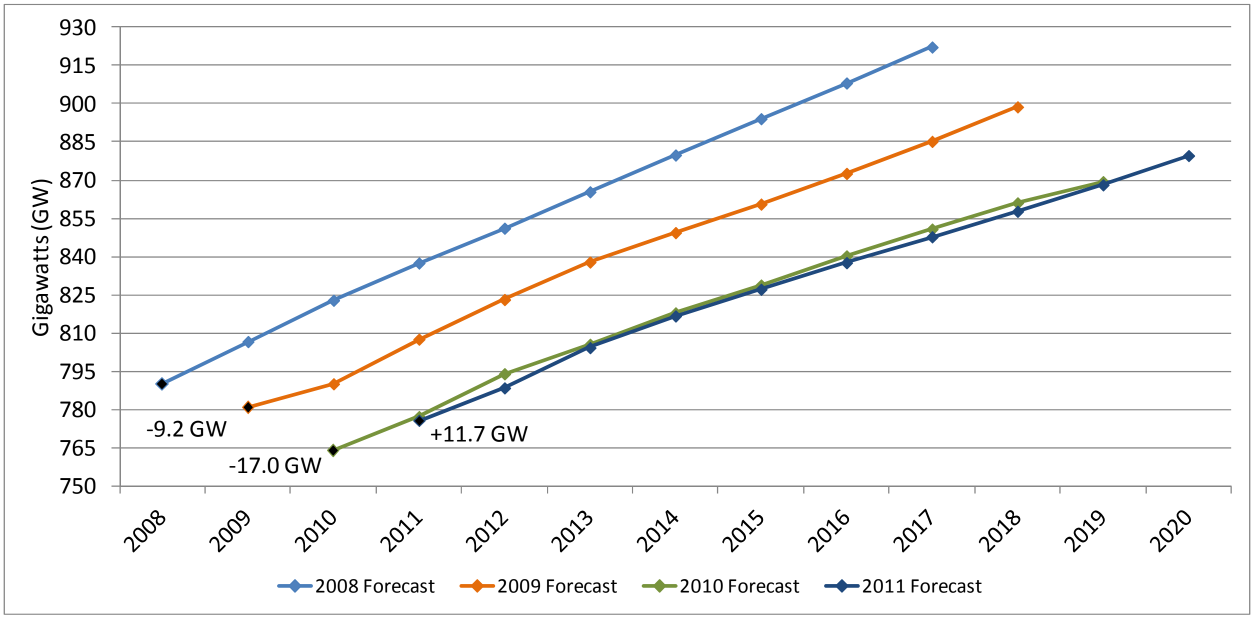
[25] http://www.Federalreserve.gov/monetarypolicy/files/20110713_mprfullreport.pdf.

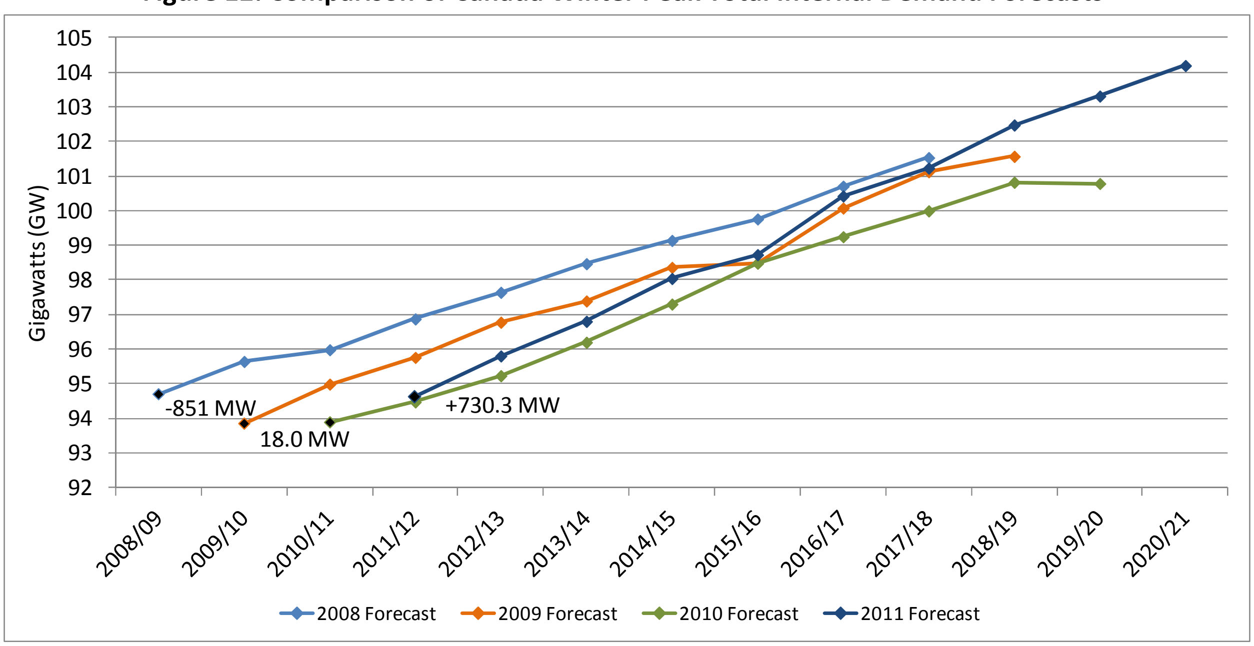
[26] http://www.chamber.ca/images/uploads/Reports/2010/Economic_Outlook_2011.pdf.

Figure 11: Comparison of U.S. Summer Peak Total Internal Demand Forecasts



In Canada, winter-peak demand forecasts are projected to increase at a much higher rate than in the United States. In fact, the 2011 forecast is projected to be in line with the 2008 pre-recession long-term forecast in the latter part of the assessment timeframe. Significant recovery is expected during the first five years, surpassing the peak demand projections in the prior two years (Figure 12).

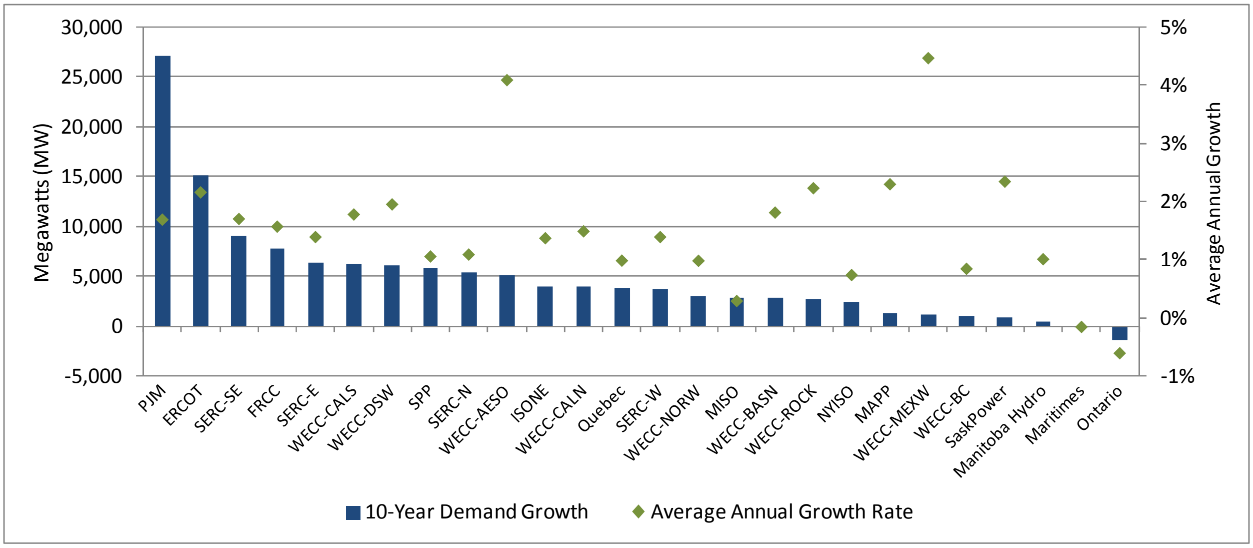
Figure 12: Comparison of Canada Winter Peak Total Internal Demand Forecasts



From a more granular perspective, growth in PJM contributes about a quarter of the 10-year growth in the U.S (Figure 13). Totaled together, ERCOT, SERC-SE, and FRCC also contribute a quarter of the growth in the U.S. While two Canadian Assessment Areas are expecting decreases in demand over the next 10-

years (Maritimes and Ontario), the growth in Canada overall is primarily attributed to the large (over four percent) average annual growth rate expected in Alberta (WECC-AESO). In Ontario, aggressive Energy Efficiency and Conservation programs are projected to reduce peak demand approximately 1,500 MW by 2021.

Figure 13: Comparison of Demand Growth and Annual Growth Rates by Assessment Area



Long-Term Forecast Uncertainty

System planners must consider the uncertainty reflected in peak demand projections in order to maintain sufficient Reserve Margins in the future.[27] Because electric demand reflects the way in which customers use electricity in their domestic, commercial, and industrial activities, the Regional forecasts are continuously enhanced as the study period approaches. The amount of electricity these sectors will demand from the bulk power system in the future depends on a number of interrelated factors:

- Future economic growth
- Price and availability of other energy sources
- Technological changes
- Higher efficiency appliances and equipment
- Customer-driven Conservation efforts
- Industrial cogeneration
- Effectiveness of industry-driven conservation and Demand-Side Management (DSM) programs

Each of these factors has its own set of uncertainties, and their effects on future electricity demand are challenging to predict.[28]

[27] 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. Actual demand may deviate from the midpoint projections due to Variability in key factors that drive electricity use. For these forecasts, there is generally a long-run 50 percent probability that actual demand will be higher than the forecast midpoint and a long-run 50 percent probability that it will be lower.

[28] A detailed primer on uncertainties in forecasting can be found in the *Load Forecast Uncertainty* section of this report.

With greater uncertainty in future electricity use attributed to the recent economic recession, continuously updating demand forecasts are essential to the planning process. Furthermore, the pace and shape of the economic recovery will dramatically influence demand growth across North America in the next 10-years. Largely unpredictable economic conditions resulted in a degree of uncertainty in the 2009 and 2010 demand forecasts not typically seen in periods of more stable economic activity. It is vital that the electric industry maintain flexible options for increasing its resource supply in order to respond effectively to rapid, upward changes in forecast electricity requirements and any unforeseen resource development issues.

According to a recent NERC report *2010 Special Reliability Scenario Assessment: Potential Reliability Impacts of Swift Demand Growth after a Long-Term Recession,* a recovery period where economic activity strengthens following a recession has been experienced in the past.[29] Depending on the magnitude and timing of the recovery period, the result of swift demand growth may result in higher than expected demand. Therefore, the complexities of predicting economic factors that will dictate the outcome of the recovery may create forecasting challenges in the near future. While the industry is prepared to handle increased demand growth over a long-term period, rapid demand growth in a short-term can create reliability issues if resources cannot be fully deployed or acquired to meet resource adequacy requirements. The severity of the recent recession, coupled with the uncertainty of the recovery magnitude, renders near-term demand estimates uncertain. Whether changes are cyclical, structural, or both, close monitoring of the recession's influence on electric demand is essential.

However, this scenario has not yet taken shape in the current forecasts. A majority of the Assessment Areas are expecting average annual growth rates of less than two percent over the next 10-years, which historically has been manageable. With the exception of a few areas of concern highlighted in the resource adequacy assessment section, supply is projected to keep up with peak demand over the long-term.

Demand-Side Management

Demand-Side Management programs, which include Conservation, Energy Efficiency, and a variety of Demand Response programs, provide the industry with the ability to reduce peak demand and to potentially defer the need for some future generation capacity. However, Demand-Side Management is not an unlimited resource and may provide limited demand reductions during pre-specified time periods. Some Regions have been using Demand-Side Management for many years, such as ERCOT, FRCC, NPCC, and WECC, while others have less penetration. Historical performance data from these Regions may also provide a way to analyze the benefits from these resources.[30] The structure of Demand-Side Management programs (*e.g.,* performance requirements, measurement and verification

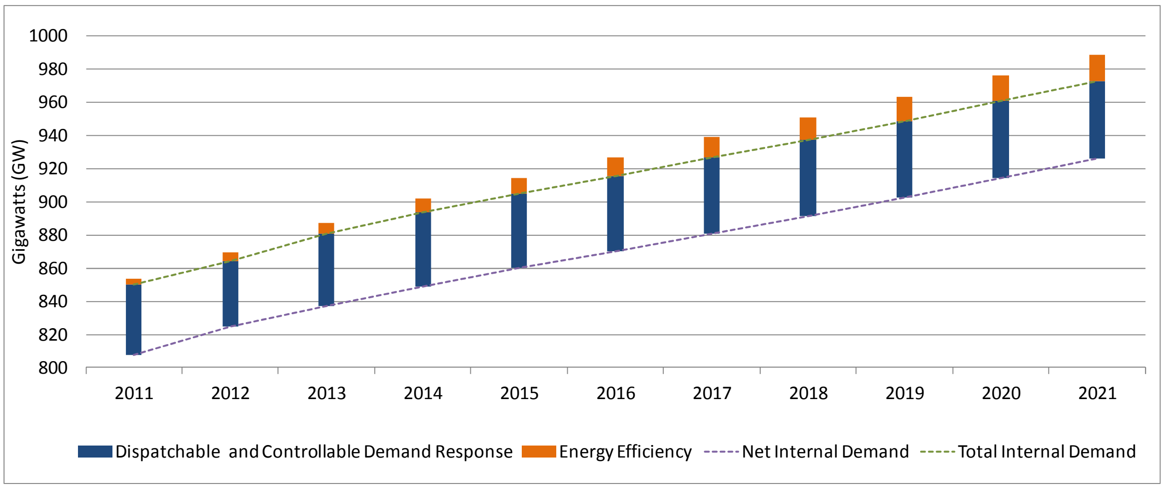
[29] http://www.nerc.com/files/NERC_Swift_Scenario_Aug_2010.pdf

[30] NERC Demand Response Availability Data System (DADS) is col"lecting Demand Response performance data on a semi-annual basis. The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable Demand Response supporting forecast adequacy and operational reliability. For more information, visit the DADS website at: http://www.nerc.com/page.php?cid=4|357.

applicability, resource criteria may be indicative of how well these programs perform when needed. The shared experiences and lessons learned from these high-penetration areas should benefit the North American bulk power system in providing more planning and operating flexibility.

All areas are projecting at least some increased availability of Demand-Side Management over the next 10-years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in the day-ahead or real-time time periods. NERC-wide, Demand-Side Management is projected to total roughly 55,000 MW by 2021 (or about 4.5 percent of the on-peak resource portfolio), effectively offsetting approximately four years of peak demand growth (Figure 14).

Figure 14: NERC-Wide On-Peak Summer Demand Projections



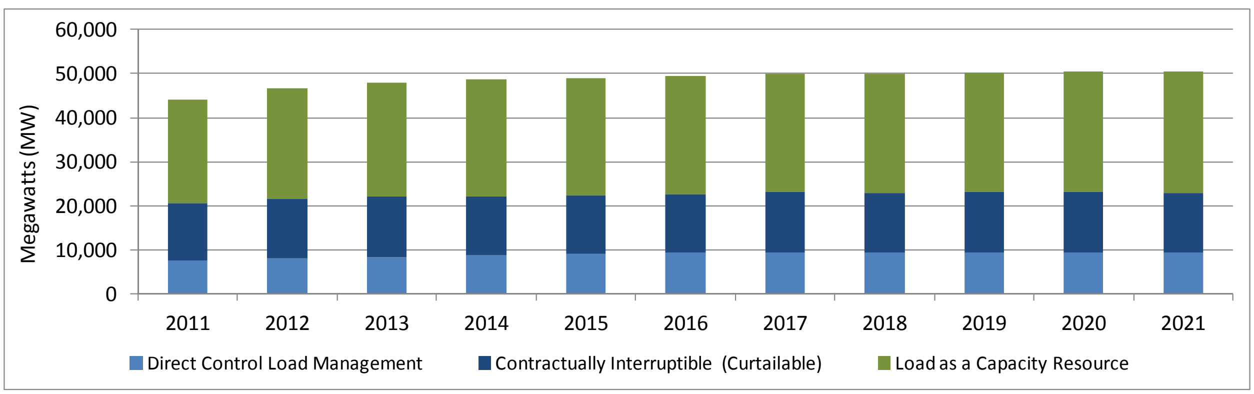
Energy Efficiency and Conservation provide permanent replacement and/or more efficient operation of electrical devices results in demand reductions across all hours of use, rather than event-driven targeted demand reductions. Energy Efficiency across all Assessment Areas is expected to reduce 2021 demand by approximately 15,300 MW on-peak. When compared to last year's 2019 forecast, an increase of almost 5,000 MW is projected. As a result of implementing Energy Efficiency programs alone, the electric industry in North America has effectively deferred the need for new generating capacity by approximately one year. The ability to implement Energy Efficiency programs in a relatively short time period provides the industry with another short-term solution to address any anticipated near-term capacity short-falls. Successful 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.

The type of Energy Efficiency programs (industrial, commercial, and residential) influences the total capacity (MW) reduction depending on the time of day and the reduction that is desired. Load forecasting is a critical component to understanding the overall peak reduction observed or projected. Tracking and validating Energy Efficiency programs is vital to increasing the accuracy of forecasts. In some areas, experience with these demand-side resources has improved. For example in ISO-NE, demand-side resources can participate just like traditional generation resources in the Forward Capacity Market.[31] The ability to demonstrate effective performance of these resources illustrates the confidence exhibited by system planners and operators in using demand-side resources to fulfill capacity obligations while maintaining the same level of reliability.

Potential drivers for the continued expansion of Energy Efficiency programs in the future are Renewable Portfolio Standards (RPS), which commonly include provisions for energy-reducing actions to account for a portion of the renewable resource requirement (generally no more than five percent of total energy use). Other policy drivers include the American Recovery and Reinvestment Act of 2009[32], which includes provisions for significant investments in energy and climate related initiatives such as smart grid applications; the proposed American Clean Energy and Security Bill of 2009[33], which established credits for reduced carbon emissions; the Climate Change Plan for Canada[34]; and several Regional, state, and provincial initiatives.[35]

In terms of Demand Response (Dispatchable and Controllable which is counted on the supply side), total expected participation for 2011 has significantly increased since last year, from just 30,000 MW to 43,000 MW. Notable growth exists in short-term projections for the next three years and plateaus in the long-term to just over 50,000 MW (Figure 16). The plateau effect represents the uncertainty in committing Demand Response beyond what is currently planned and contracted.

Figure 15: NERC-Wide On-Peak Dispatchable and Controllable Demand Response Projections



Uncertainty exists not only in how much peak demand reduction will actually be realized at the particular time when Demand Response is needed and deployed, but also in the long-term sustainability of these resources.[36] Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of Demand Response involve greater forecasting uncertainty.

31 http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/cap_mkt/index.html.

32 http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.txt.pdf.

33 http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h2454pcs.txt.pdf.

34 http://dsp-psd.pwgsc.gc.ca/Collection/En56-183-2002E.pdf.

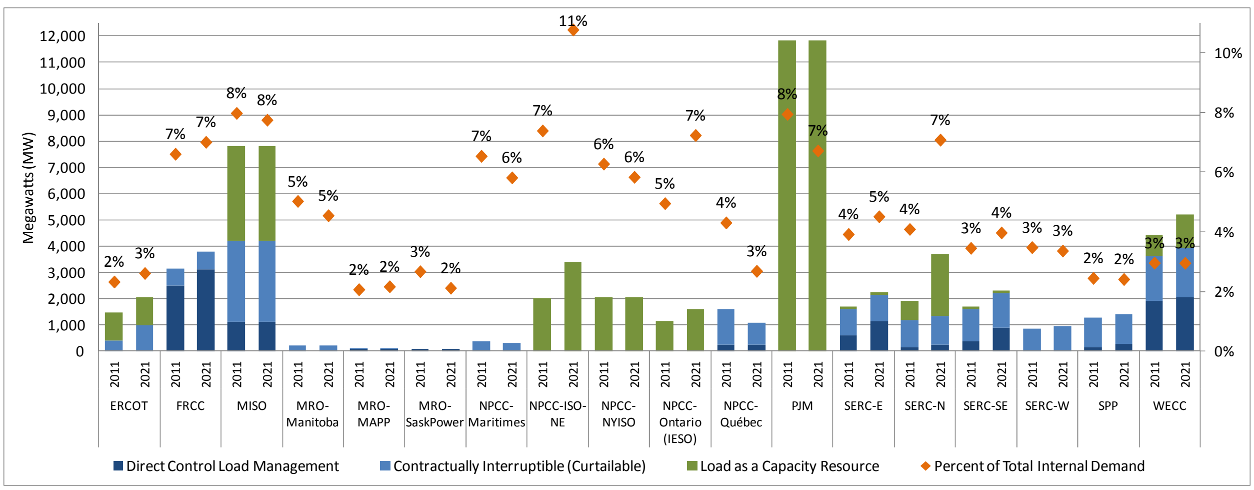
35 Reliability Impacts of Climate Change Initiatives report: http://www.nerc.com/files/RICCI_2010.pdf

36 Refer to the 2010 Emerging Reliability Issues: Uncertainty of Sustained Participation in Demand Response Programs section.

Because participation in Demand Response programs is highly dependent on a number of economic variables and incentives, it is challenging to forecast how much Demand Response will be available past three or four years.[37]

In almost all Assessment Areas, flat or slightly increased Demand Response participation is projected over the assessment timeframe. PJM and MISO administer approximately 11,900 MW and 7,900 MW of Demand Response, respectively. These relatively large Demand Response participation values represent about eight percent of the Total Internal Demand for each of the areas, (Figure 16). MISO and PJM continue to expand the types of Demand Response offered in the market, including Demand Response providing ancillary services to accommodate wind forecast errors and other system contingencies. In NPCC-ISO-NE, Demand Response projections surpass 11 percent of forecast Total Internal Demand—the most significant penetration of Demand Response seen to date.[38] Other notable increases are projected for ERCOT, NPCC-Ontario, and SERC-N. Additional Demand Response in ERCOT may improve resource adequacy issues in the Region.

Figure 16: NERC-Wide On-Peak Dispatchable and Controllable Demand Response Projections



KEY FINDINGS - DEMAND-SIDE MANAGEMENT

Significant increases in Demand-Side Management continue to offset future resource needs, while dispatchable and controllable types expand flexibility for operators.

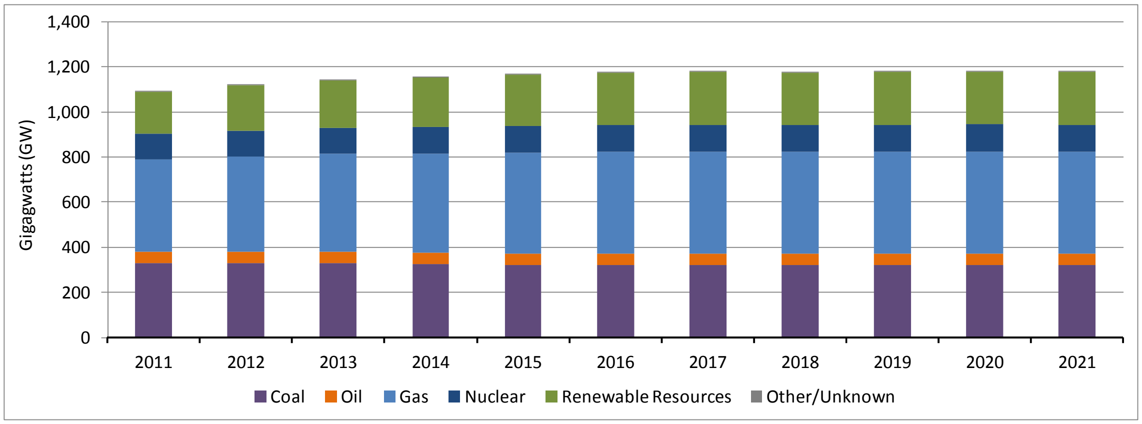
[37] In most cases, actual forecasting of Demand Response is not performed, per se. Rather projections are based on resource requirements and the amount of capacity contracted during a given commitment period--usually between one to three years.

[38] NPCC-ISO-NE projects Demand Response to reach over 11 percent of Total Internal Demand in 2013 (not shown in Figure 16)

Generation

NERC-wide total capacity[39] is projected to increase by approximately 90,000 MW[40] during this assessment period (Figure 17). Total capacity growth has significantly declined compared to the prior year projection of approximately 131,000 MW, illustrating a decline in commitments among planners to build additional generation. Again, this is primarily due to uncertainty posed by economic conditions and potential environmental regulations. In addition, reduced capacity may also be a reaction to reduced long-term peak demand and energy projections in a majority of the Assessment Areas.

Figure 17: NERC-Wide Long-Term Projected On-Peak Capacity



Two unprecedented resource-mix evolutions are beginning to take shape.

- Gas-fired generation replacing coal-fired generation
- Large increases in renewable, variable generation capacity

Natural gas, wind, and some solar generation are projected to be the primary source of new generating resources being integrated into the bulk power system during the assessment period (Figure 18). These resources are expected to slowly replace coal-fired generation, with renewables providing most of the growth. Approximately 7,000 MW of additional *Future-Planned* nuclear capacity is also expected—far less than gas and renewable, but relatively significant when compared to nuclear capacity growth over the past 30 years.

[39] Existing-Certain and Existing-Other.

[40] Includes all *Future-Planned* and *Future-Other* capacity additions (does not include Conceptual capacity additions).

Figure 18: NERC-Wide Cumulative Annual *Future-Planned* Resources by Fuel-Type

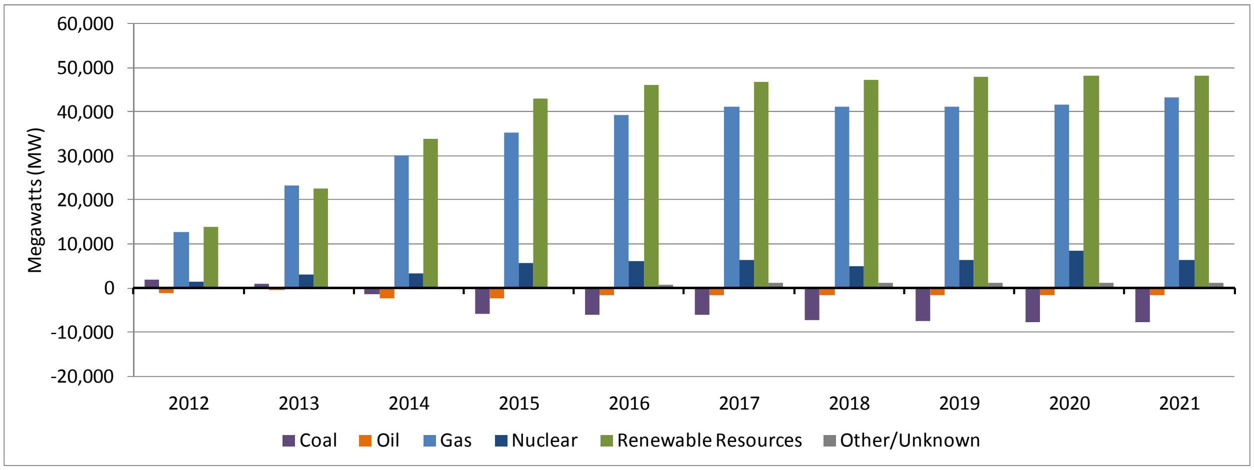
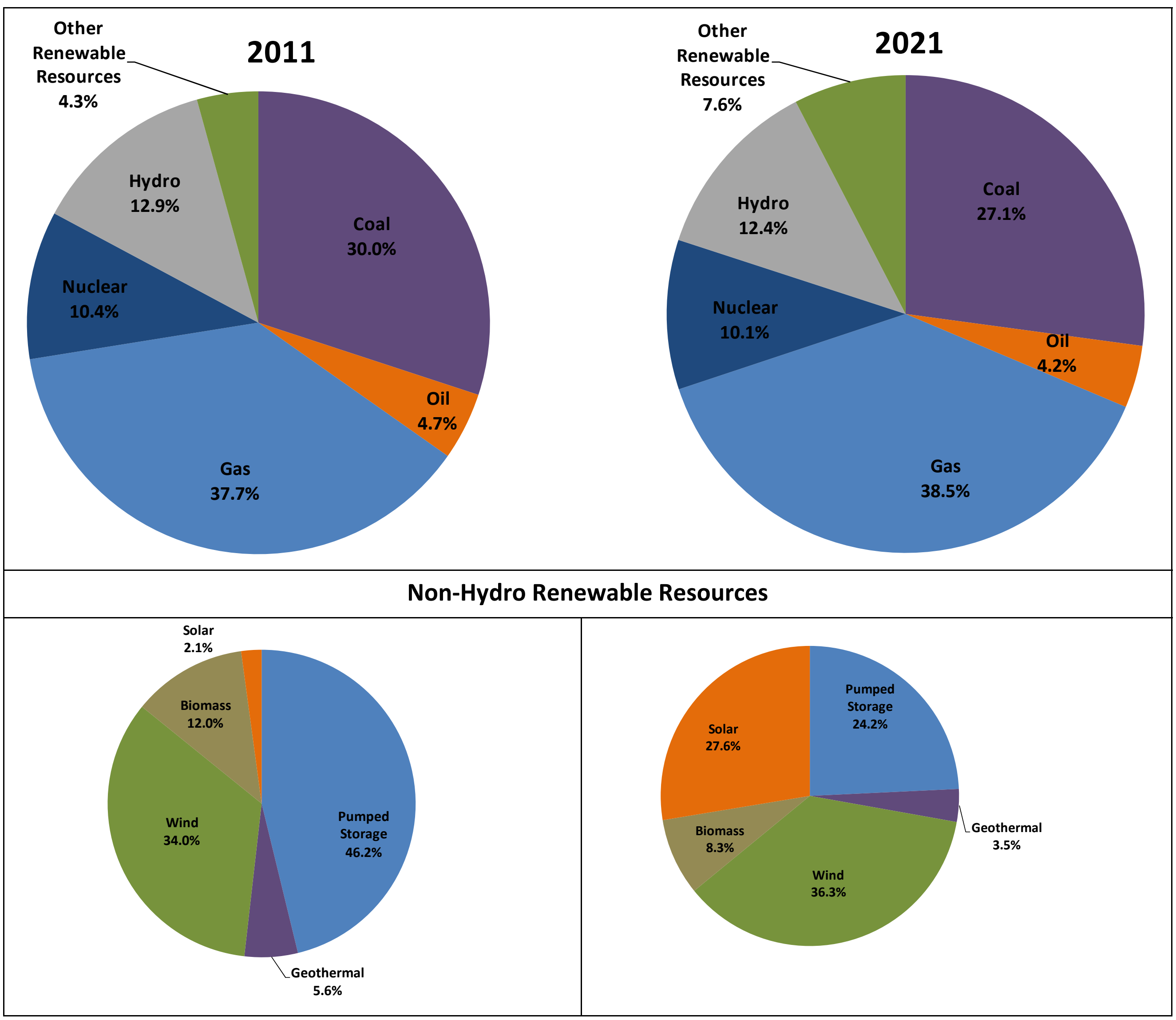


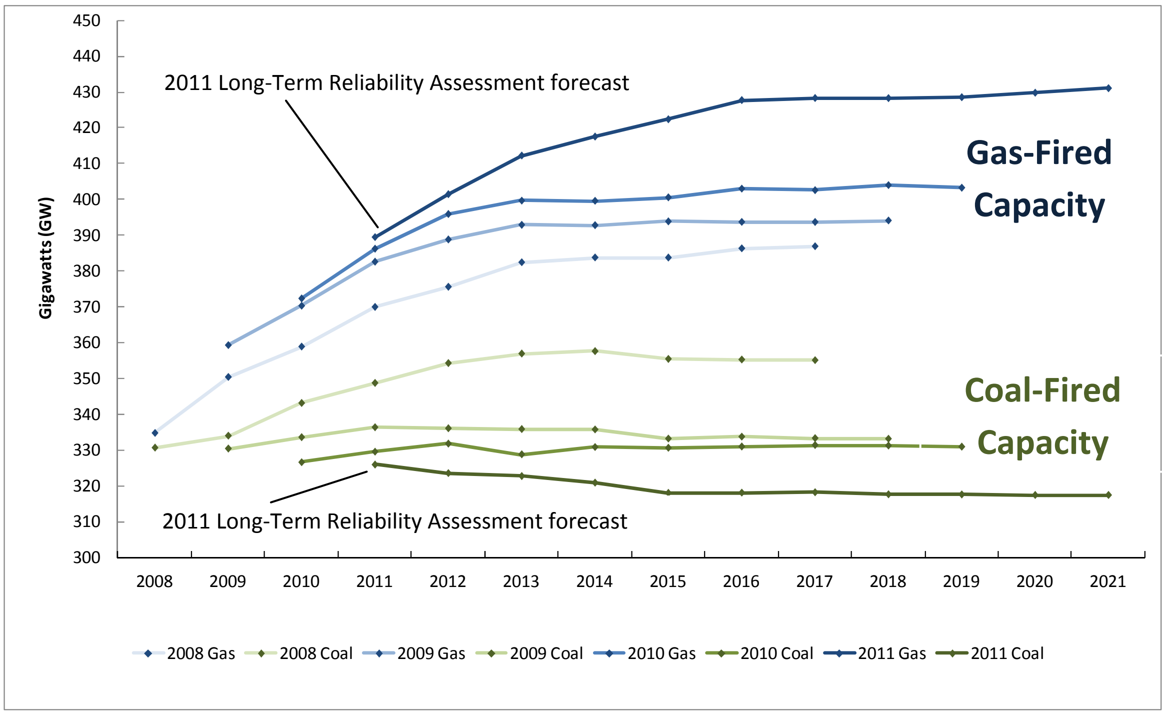
Figure 19: NERC-Wide Existing and Future Projected Fuel-Mix



In terms of the on-peak fuel mix, the most significant changes occur with a decrease of 3 percentage points in coal-fired capacity and about a 3 percentage point increase in renewable on-peak capacity—primarily wind and solar (Figure 19).

From a historical perspective, the evolution from coal to gas is evident (Figure 20). The 2011 forecast projects significant divergence of these two fuels when compared to the 2008 forecast. For the first time, NERC-wide net coal capacity is projected to decline over the 10-year period. At the same time, not only is a considerable amount of gas-fired capacity being added, but it is also projected at much higher levels than in past 10-year forecasts.

Figure 20: NERC-Wide Forecast Comparison of On-Peak Gas- and Coal-Fired Capacity Projections[41]



Coal

NERC-wide *Existing-Certain* and *Existing-Other* coal resources amounted to approximately 326 GW (or 30 percent) of total generation in 2011 and is expected to fall by over 8 GW to 318 GW by 2021. This decline can be primarily attributed to existing and pending environmental regulations that have created a general reluctance throughout the industry to solidify plans for future coal generation. Although coal is projected to provide 27.2 percent of the total generation mix in North America by 2021, substantial potential exists for further declines since retirements have not all been announced in the long-term. Certain Assessment Areas with higher dependency on coal, including ERCOT, PJM, MRO-MAPP, and SPP still project additions in coal generation. However, these increases are off-set by significant coal-fired retirements in SERC-E, SERC-N, SERC-SE, Ontario, and MISO. Most of these planned retirements in the

[41] Includes *Future-Planned* and *Future-Other* capacity projections from 2008, 2009, 2010, and 2011 LTRA data.

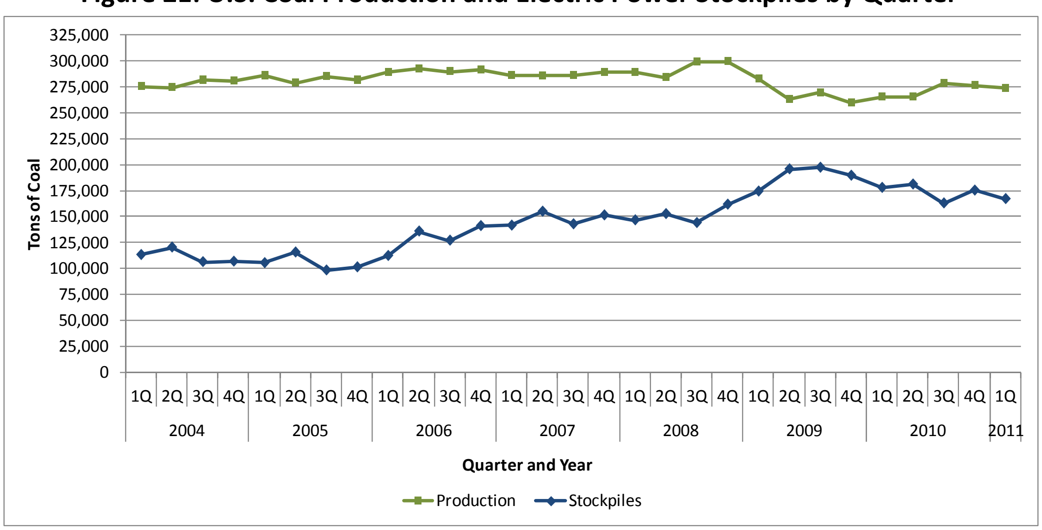
United States do not address the specific impacts of pending environmental policies, discussed in subsequent sections of this report.

In Canada, coal's contribution to the capacity mix varies greatly by province. In Ontario, four units were retired in 2010 with two more to be shut-down during 2011. By 2014, the province plans to phase out any remaining coal-fired plants. In Manitoba Hydro, there is only one remaining coal plant, though with pending environmental regulations, it is projected to retire by 2019. Other Canadian Areas that are more dependent on coal, such as SaskPower and Maritimes, project little variation throughout the assessment period.

The drop in coal demand led to sharp increases in customer stockpiles as generators continued to take delivery of coal contracted when demand expectations were higher. Stockpiles fell last year peaking to just over 275 million tons (Figure 21). In 2009 and 2010, generators cut back deliveries to match the lower burn and are likely to cut deliveries of coal further to bring existing inventories back to lower levels. The reduced purchases by generators have forced mine closures, especially in Appalachia, where the cost of coal production is higher than the rest of the industry.

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

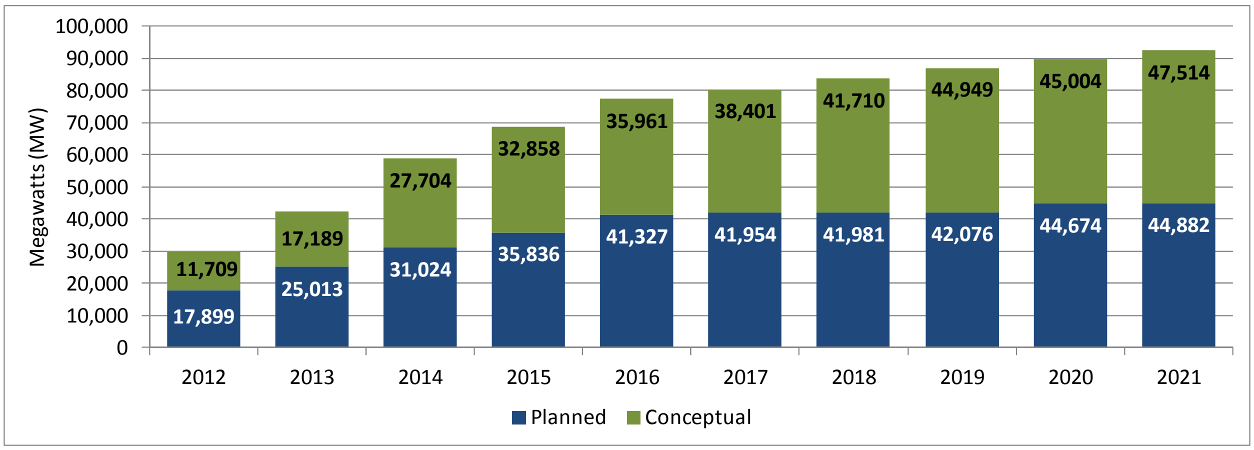
Figure 21: U.S. Coal Production and Electric Power Stockpiles by Quarter



Gas

A large portion of long-term capacity additions are projected to be gas-fired, reinforcing expectations that gas will continue to serve as the primary fuel for electricity generation in North America. While the role of unconventional gas production in bolstering North American supply is an obvious driver for the increased capacity projections, it is not the only driver. Total renewable capacity additions[42] (excluding hydro) make up the largest increase of *Future-Planned* resources, with gas-fired capacity a close second. With 47,913 MW of variable generation (expected on-peak capacity) coming on-line by 2021, gas-fired generation is often a solution to provide flexibility in managing the variability of certain renewable resources.. In areas where there is little variable generation, future gas-fired capacity is the result of retiring coal-fired capacity (*e.g.,* SERC). NERC-wide, 44,882 MW of gas-fired capacity (*Future-Planned*) is expected to be in-service by 2021—an additional 47,514 MW are classified as *Conceptual* (Figure 22). Notable increases are seen in the NYISO, ISO-NE, FRCC, SERC-SE, SERC-E, MRO-SaskPower, and SPP where several existing units (such as coal) facing retirement are often converted or re-powered to run on natural gas.

Figure 22: NERC-Wide Projections for Gas-Fired Capacity Additions



With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation a premier choice for new generating capacity in the future. However, increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies, such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other Regions, can contribute to managing interdependency risks and ensure reliability is maintained regardless of the fuel-mix.

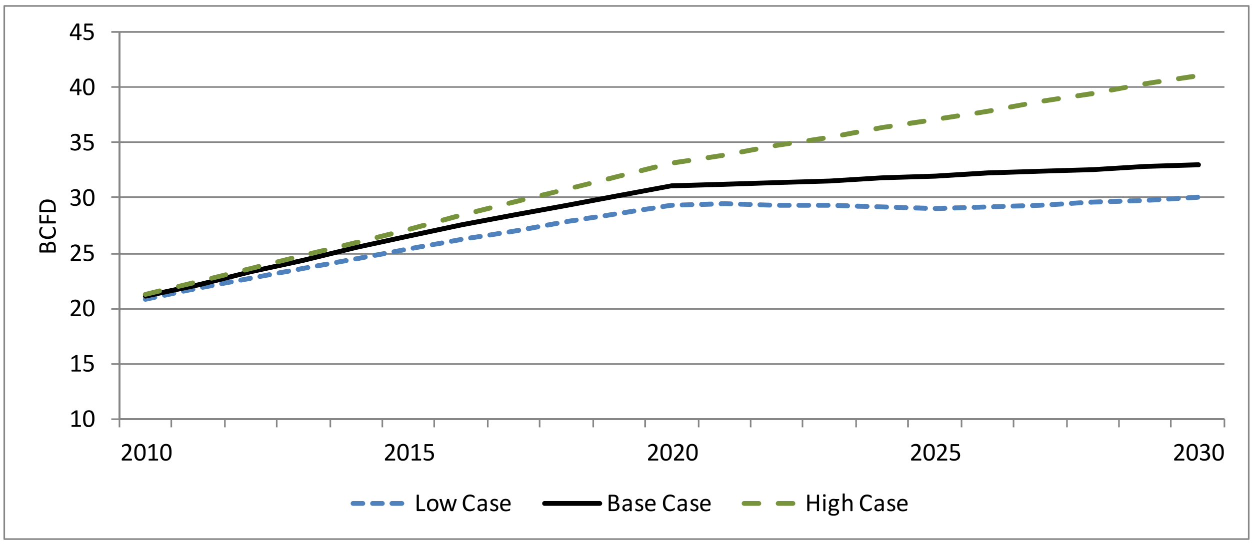
Almost all of the future growth in natural gas demand will come from the electric sector. However, there is a wide range of views on the potential growth for electric sector gas demand, because gas-fired generation currently tends to be at the margin and is impacted by the actions of all other forms of electric power generation. Nonetheless, changes in the electric sector (*i.e.,* growth in gas demand,

[42] *Future-Planned* and *Future-Other* capacity additions for pumped storage, geothermal, wind, biomass, and solar.

decrease in coal generation) will ultimately increase gas demand levels due to the more base-load functions gas-fired generation is expected to provide in the near future. The range of potential growth in electric sector gas demand over the next two decades is between 30 and 41 BCFD, which equates to about 2.0 to 3.6 percent per annum growth rate (Figure 23).[43]

Long-term growth of gas-fired generation also needs to be taken into account in pipeline planning and operations. The combination of this growth in gas demand within the electric sector and its changing status among the gas consuming sectors has significantly increased the interdependencies of the electric and gas industries, causing many participants within both industries to focus sharply on their interface. A key element of focus between the two industries is the need for increased coordination, particularly at a regional level.

Figure 23: Scenarios for Electric Sector Gas Demand



Among other things, on-going pipeline expansion will provide both increased reliability and diversification of gas supplies to the electric industry, shown in millions of cubic feet per day (MMCFD) and by pipeline miles.

To address these concerns, NERC published the 2011 Special Reliability Assessment: A Primer on the Natural Gas and Electric Power Industries Interdependency, which takes a broad view within North America at how the growing interdependence of gas and electric industries can impact electricity production and overall reliability. The Phase I primer reviews projected gas supply, projected pipeline infrastructure, the electric-gas industry interface, as well as the challenges of aligning a relatively slow moving product (i.e., gas) with a fast moving end product (i.e., electricity). Phase II of the study is currently under development and is expected to assess system vulnerabilities associated with the growing interdependence of the two industries.

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[43] Assumptions are described in the 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States report: http://www.nerc.com/page.php?cid=4|61, December 2011

A call to harmonize the interaction between the natural gas and electric industries was recently highlighted in a study by the Natural Petroleum Council. The report recommends the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the North American Energy Standards Board, the National Association of Regulatory Utility Commissioners, and each formal wholesale market operated by the Regional Transmission Organizations to develop policies, regulations, and standardized business practices that improve the coordinated operations of the two industries and reduce barriers that hamper the operation of a well- functioning market, increase the transparency of wholesale electric power and natural gas markets, and address the issue of what natural gas services generators should hold. The recommendations from this report reconfirm this emerging issue and present a call to action from all stakeholders. This expansion includes additions for all gas customers, with the electric industry consuming approximately 30 percent of the demand; this share is growing.

Pipeline infrastructure and capacity is expanded based on firm contracts from its consumers. Despite the growth and future expansion of pipeline capacity, more pipeline capacity will ultimately be needed to support the gas-fired capacity build out. Much of the projected gas-fired capacity does not have firm pipeline service contracted, as this type of service is not expected to be needed for serving mid-range and peak demands. However, with environmental regulations potentially causing coal-fired base-load units to retire, gas-fired generation will likely be needed to serve more base-load demand. In essence, for every megawatt of coal fired generation that is retired and replaced with gas-fired capacity, an increase of 0.168 MMCFD (61.4 MMCF annually) of gas supply is needed.44 As a rough estimate, if 50 GW of coal-fired capacity were to retire and be replaced by gas-fired generation (providing base-load capacity and operating all hours of the day, everyday), an additional 1,200 miles of gas pipelines will be needed solely to support future gas-fired capacity.[45] This is based on the most recent five-year average capacity per mile of approximately 7 MMCFD/mile. This translates into more pipeline capacity that will be needed to serve the demands of the electric industry than what is currently and projected to be contracted for firm service and also aligns with the high-case electric sector demands.

To address these concerns, NERC published the *2011 Special Reliability Assessment: A Primer on the Natural Gas and Electric Power Industries Interdependency*,[46] which takes a broad view within North America at how the growing interdependence of gas and electric industries can impact electricity production and overall reliability. The Phase I primer reviews projected gas supply, projected pipeline infrastructure, the electric-gas industry interface, as well as the challenges of aligning a relatively slow moving product (*i.e.,* gas) with a fast moving end product (*i.e.,* electricity). Phase II of the study is currently under development and is expected to assess system vulnerabilities associated with the growing interdependence of the two industries.

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[44] Assuming, on average, a 500 MW combined-cycle unit burns 84,000 MMBtu/day and operates 24 hours in a day, 365 days a year. http://www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf

[45] At 0.168 MMCFD/MW, multiplied by 50 GW equals 84,000 MMCFD of gas demand. This is then divided by the 5-year average MMCFD per mile—approximately 7 MMCFD/mile. This relatively simple calculation provides an indication on how many miles of additional pipeline capacity may potentially be needed based on historical observations, but does not necessarily establish definitive future needs.

[46] 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States report: http://www.nerc.com/page.php?cid=4|61, December 2011

A call to harmonize the interaction between the natural gas and electric industries was recently highlighted in a study by the Natural Petroleum Council.[47] The report recommends the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the North American Energy Standards Board, the National Association of Regulatory Utility Commissioners, and each formal wholesale market operated by the Regional Transmission Organizations to develop policies, regulations, and standardized business practices that improve the coordinated operations of the two industries and reduce barriers that hamper the operation of a well- functioning market, increase the transparency of wholesale electric power and natural gas markets, and address the issue of what natural gas services generators should hold. The recommendations from that report reconfirm this emerging issue and present a call to action from all stakeholders.

Figure 24: Comparison of Current U.S. Gas Pipeline Expansions with Historical Results – Capacity

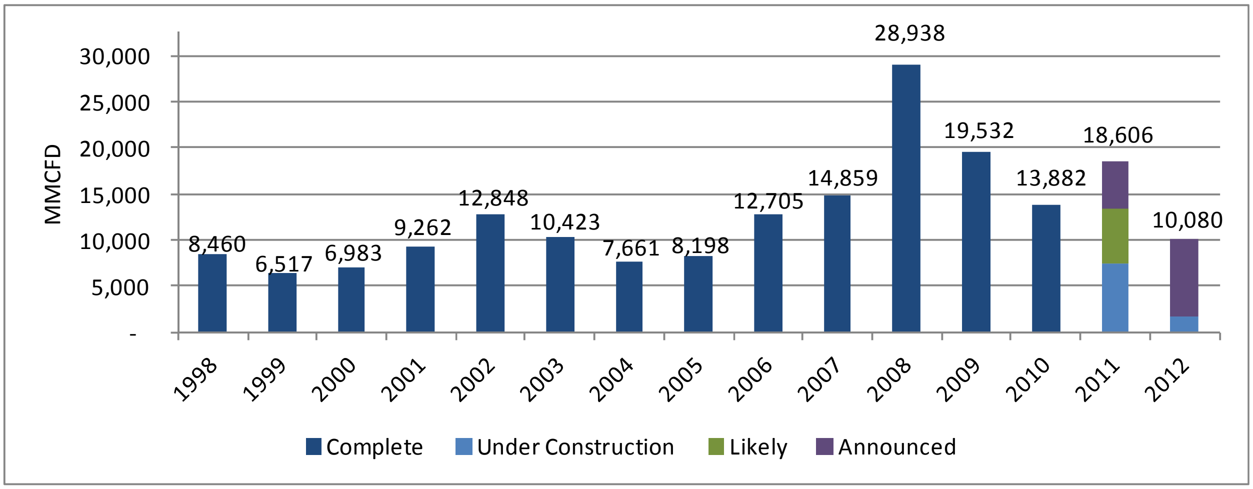
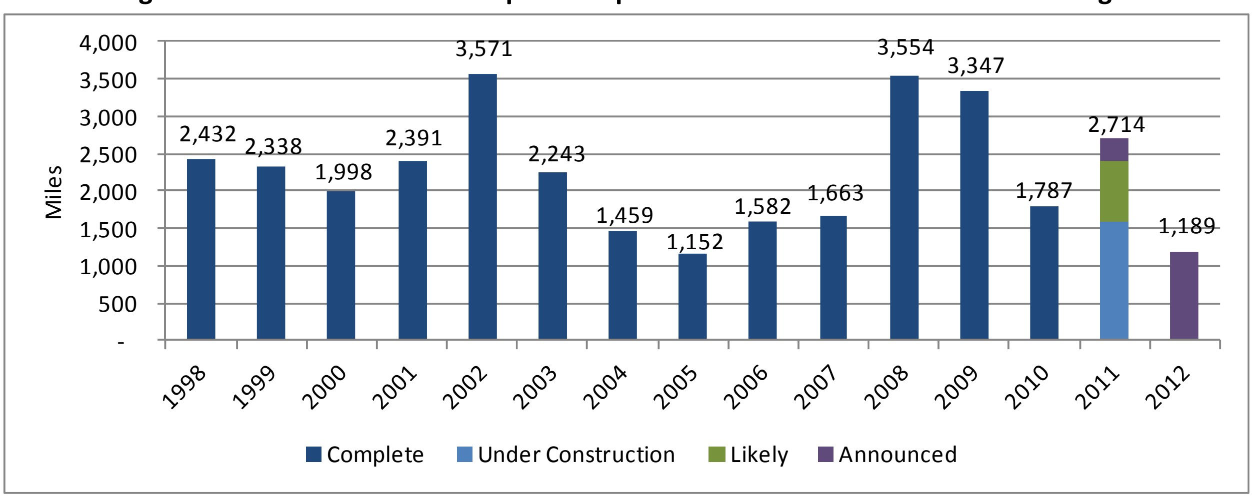


Figure 25: of Current U.S. Gas Pipeline Expansions with Historical Results – Mileage



[47] Prudent Development – Realizing the Potential of North America's Abundant Natural Gas and Oil Resources: Executive Summary: http://downloadcenter.connectlive.com/events/npc091511/Executive_Sumary-91511.pdf.

KEY FINDINGS - GAS ELECTRIC INTERDEPENDENCY

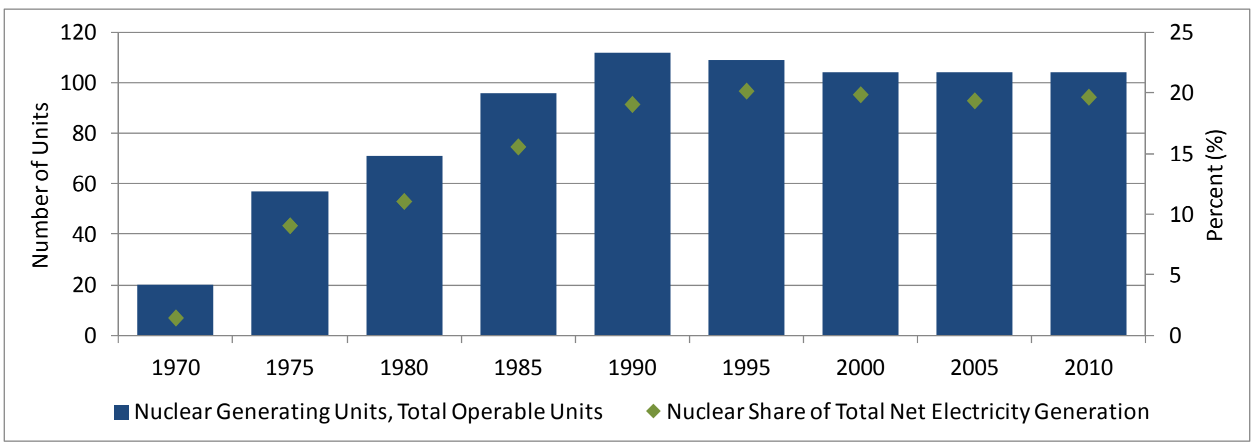
The growing dependence on natural gas as a primary fuel source of on-peak capacity must be considered in planning; operational measures must be in place to minimize interdependency risks particularly during off-peak periods as more gas-fired generation is expected to provide base-load functions.

Nuclear

The amount of nuclear capacity has essentially remained consistent throughout the past two decades (Figure 26). However, concerns for the future of nuclear generation have resurfaced in the aftermath of the Fukushima Dai-ichi nuclear plant incident following the massive earthquake and tsunami in Japan. Unlike in Europe, the aftershocks in the United States from Japan's nuclear disaster caused by the March 11, 2011 earthquake are likely to be borne by existing nuclear plants than by proposed new reactors. These new challenges add to existing concerns that have plagued the expansion of nuclear power since the 1970s, including high capital costs and scarcity of funding support, such as Federal loan guarantees, compared with the low overall costs of building other capacity, such as gas-fired generation. Accordingly, most countries with heavy reliance on nuclear power are putting current policies under additional scrutiny. Japan has voiced general intentions to reduce dependency on nuclear generation.

In Europe, the repercussions have been even more severe. Italy rejected government plans in a June 12-13, 2011 referendum to build any additional nuclear plants. Also in mid-June Switzerland voted to phase out its 3,049 MW of nuclear reactors by 2034[48] while Germany recently announced plans to retire all nuclear units by 2022.

Figure 26: U.S. Nuclear Capacity and Share of Net Electricity Generation[49]



48 http://www.platts.com/NewsFeature/2011/Fukushima/index.

49 http://www.eia.gov/totalenergy/data/annual/index.cfm#electricity.

In North America, nuclear energy remains an important part of the generation mix, accounting for approximately 10 percent of total U.S. and Canadian on-peak capacity. A number of initiatives have been taken by the respective commissions in both countries. Specifically, the U.S. Nuclear Regulatory Commission (NRC) assigned a task-force that systematically and methodically reviewed the current NRC processes and regulations. This task force produced a report[50] with long- and short-term recommendations regarding whether or not the NRC should make additional improvements to its regulatory system and policy direction, and ultimately enhance nuclear reactor safety in the United States. Similarly, the Canadian Nuclear Safety Commission (CNSC) appointed a task force to examine lessons learned from the Japan accident. The task force will recommend short- and long-term measures to address any significant safety gaps at all Canadian nuclear power plants, and determine whether any design modifications are needed. It will identify priorities for the implementation of corrective actions based on the lessons learned and the need, if any, for further study. The CNSC also ordered all Canadian reactor operators to revisit their safety plans and report on potential improvements to be made.

Based on data collected for this long-term assessment, NERC does not currently project a major shift away from nuclear energy in North America. However, the outlook for new units has been significantly reduced compared to a year earlier. The long-term projections amount to a net increase of 6,500 MW. It is important to note that a portion of this increase can be attributed to plant refurbishments, upgrades, or units coming back into services after maintenance outages. In FRCC, the Crystal River 3 unit will be returned to service, adding approximately 1,000 MW of nuclear capacity between 2013 and 2014. The Maritimes Area will return 660 MW of operating capacity to the system by 2013 with the completed refurbishment of the Point Lepreau nuclear generating station.

Some of these projections do account for new unit additions, usually at existing plants. Examples include the Vogtle units in SERC-SE. In Ontario, where 50 percent of all generation is supplied by nuclear, the Pickering Nuclear facility could face retirement during this assessment period. The Ontario government will ultimately make decisions in 2012 regarding the retirement of the Pickering plant, as well as potential refurbishment activities on other units during the long-term planning horizon.

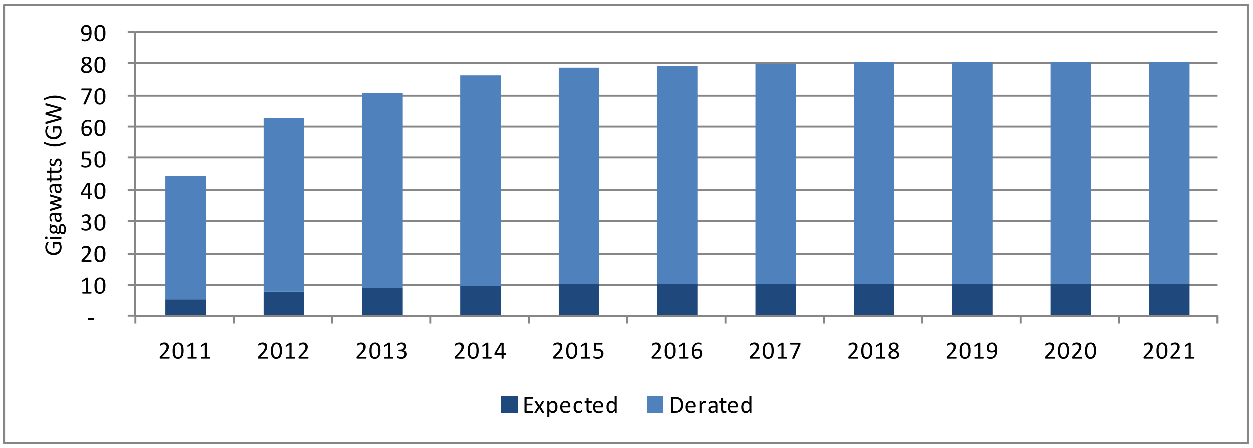
Wind

Variable resources – especially wind – are growing in importance in many areas of North America as the number of new facilities continues to increase. It is vital to ensure that these variable resources are reliably integrated into the bulk power system, addressing both planning and operational challenges.[51] Nameplate wind capacity is projected to grow by almost 36,000 MW during this assessment period (Figure 27).

[50] http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf

[51] Accommodating High Levels of Variable Generation: Summary Report: http://www.nerc.com/files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf.

Figure 27: NERC-Wide Projected Wind Capacity



Despite these high expectations for the build-out of nameplate wind generation, this variable resource has a higher derate than any other renewable energy source. Expected on-peak capacity is expected to grow from approximately 5,400 MW in 2011 to over 10,200 MW in 2021. These additions are expected primarily in ERCOT, MISO, NPCC (Canada), PJM, SPP and WECC. These projected resources, categorized as *Future-Planned* and *Future-Other*, have more certainty compared to *Conceptual* resources, with confidence factors typically ranging from 10 to 20 percent. If these *Future-Planned* resources come to fruition, NERC-Wide wind capacity will nearly double by 2021 (Table 3).

A variety of drivers cause wind to outpace many other resources in terms of projected capacity additions, including Federal, state and provincial tax credits and state Renewable Portfolio Standards (RPS) requirements, which have accelerated the integration of wind generation in ERCOT, MISO, NPCC (U.S.), and WECC. These Assessment Areas project the pace of integration to continue through 2021.

However, the actual capacity output of wind plants during times of peak demand generally amount to a fraction of nameplate capacity. For example, expected on-peak capacity can account for as little as 8 percent of an Assessment Area's entire nameplate wind capacity. As noted by NERC in prior assessments, consistent methods to determine on-peak wind capacity are needed ensuring uniform measurement and resource adequacy assumptions.[52] As wind generation becomes a more significant contributor to an area's capacity mix, probabilistic planning techniques will be needed. More consistency is being achieved given more experience with larger portfolios of wind generation.

[52] Currently, Regions and subregions (in particular, difference operating entities) use different methods to determine expected on-peak values of wind capacity. The Integration of Variable Generation Task Force is addressing this issue. The report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* is available on the NERC website at: http://www.nerc.com/files/IVGTF1-2.pdf.

Table 3: NERC-Wide Existing and Projected Nameplate Wind Projections

Assessment Area	Existing Capacity			Planned Capacity			Conceptual Capacity		
	2011	2011	2011	2021	2021	2021	2021	2021	2021
	Expected	Derated	Nameplate	Expected	Derated	Nameplate	Expected	Derated	Nameplate
ERCOT	820	8,607	9,427	951	9,980	10,931	2,790	28,232	31,023
FRCC	-	-	-	-	-	-	-	-	-
MISO	389	7,683	8,072	664	9,542	10,206	285	1,924	2,209
MRO-Manitoba	-	242	242	-	242	242	-	-	-
MRO-MAPP	398	768	1,166	398	768	1,166	-	-	-
MRO-SaskPower	40	158	198	75	298	373		-	-
NPCC-Maritimes	314	467	780	355	597	953	-	40	40
NPCC-New England (ISO-NE)	26	90	116	169	557	726	2,525	-	2,525
NPCC-New York (NYISO)	131	1,180	1,311	147	1,324	1,471	484	4,356	4,841
NPCC-Ontario (IESO)	173	1,161	1,334	650	4,347	4,997	269	1,797	2,066
NPCC-Québec	141	541	681	941	2,407	3,348	-	-	-
PJM	670	4,273	4,942	1,138	6,341	7,480	4,712	19,413	24,125
SERC-E	-	-	-	-	-	-	-	-	-
SERC-N	152	132	284	152	132	284	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	10	190	200
SPP	260	3,135	3,395	339	3,847	4,186	1,987	19,968	21,955
WECC-AESO	713	227	940	2,441	879	3,320	-	-	-
WECC-BASN	515	1,494	2,009	577	2,051	2,628	427	453	880
WECC-BC	23	124	147	109	812	921	-	-	-
WECC-CALN	300	913	1,213	446	1,681	2,127	-	200	200
WECC-CALS	3	1,548	1,551	31	12,017	12,048	-	-	-
WECC-DSW	25	559	584	25	559	584	5	1,428	1,433
WECC-NORW	119	5,107	5,226	301	10,485	10,786	1,134	2,519	3,653
WECC-ROCK	164	956	1,120	346	1,374	1,720	126	1,044	1,170
WECC-MEXW	4	6	10	4	6	10	-	-	-
Total-NERC	5,379	39,370	44,749	10,259	70,247	80,505	14,753	81,566	96,319

In certain Areas, where large concentrations of wind resources have been added, system planners must accommodate added variability by increasing the amount of available regulating reserves, and potentially carrying additional Operating Reserves. Because weather plays a key factor in determining wind output, enhancing Regional wind forecasting systems can provide more accurate output projections. Other methods include wind curtailment and limitation procedures used when generation exceeds available regulating resources.

Expected on-peak wind capacity is projected to increase substantially by 2021, with the largest contributions coming from ERCOT, PJM, and SPP (Figure 28 and Figure 29).With significant plans for new nameplate wind capacity, a 2 percentage point increase is also projected in its on-peak contribution of to capacity. Because this value is calculated from a NERC-Wide perspective, growth of wind capacity in areas that count more of their nameplate capacity for on-peak capacity can skew the NERC-wide value. For example, significant growth in an Assessment Area that counts 20 percent of wind plant nameplate capacity compared to only slight growth in an Assessment Area that counts 10 percent, will increase the NERC-wide ratio of nameplate to on-peak capacity.

Figure 28: NERC-Wide Nameplate and On-Peak Capacity Projections

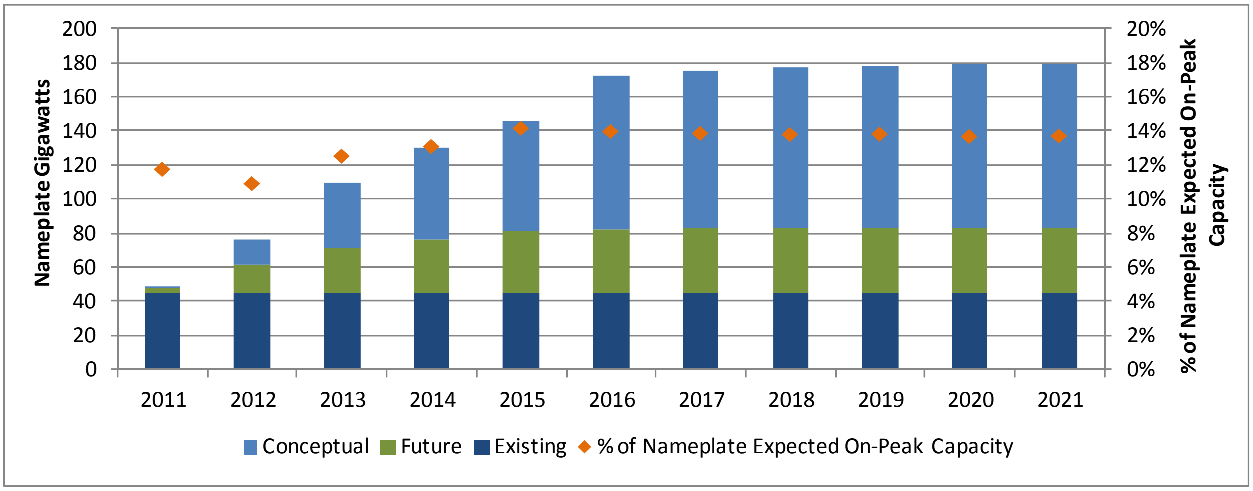
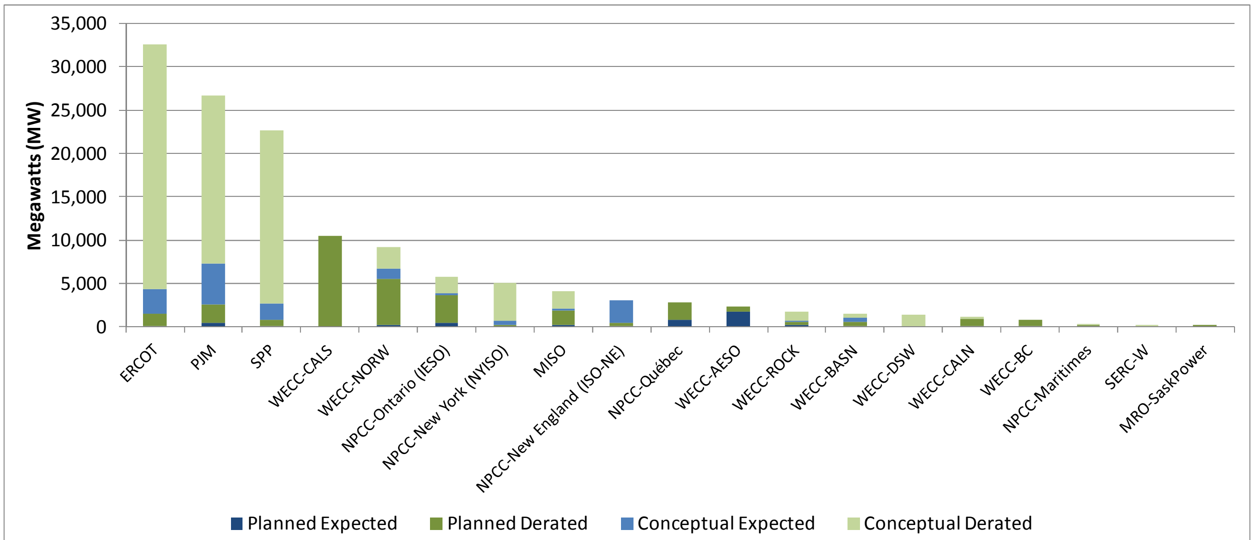


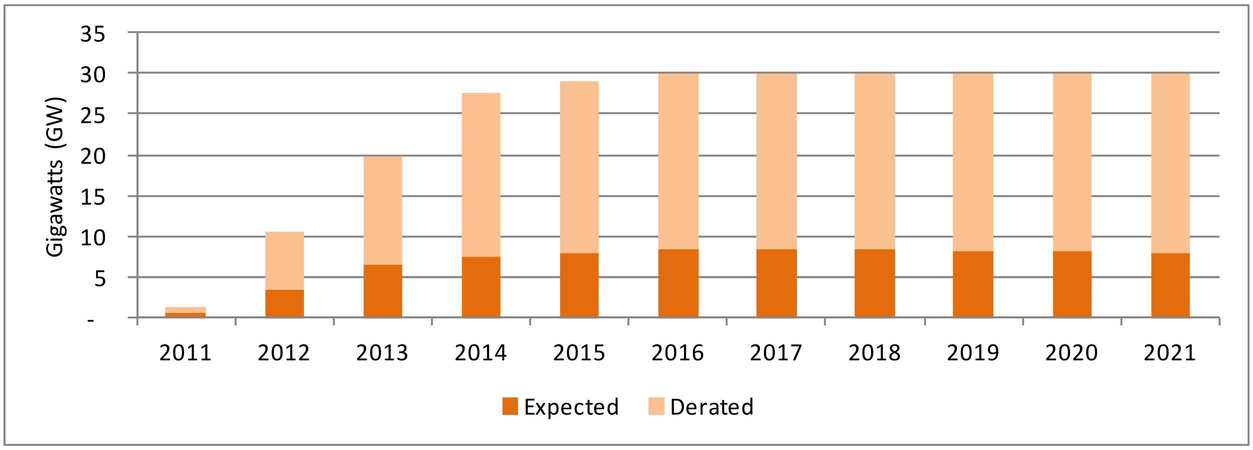
Figure 29: Additional 2021 Wind Capacity by Assessment Area



Solar

Compared to other renewable resources, solar generation will see the largest growth in nameplate capacity additions during the next five years (Figure 30). Approximately 28.5 GW of nameplate capacity will be added, primarily in the Western Interconnection, with the California South (CALS) subregion projecting almost 23 GW during this assessment period. Several Regional planners are currently conducting studies to determine the best methods to incorporate this variable resource into the generation mix.

Figure 30: NERC-Wide Projected Solar Capacity[53]



VARIABLE GENERATION

Significant growth in wind and solar generation continues to be projected, surpassing the NERC-wide on-peak capacity forecasts of all other types of generations. Tools, training, and transmission remain key to successful planning and operations.

Hydro

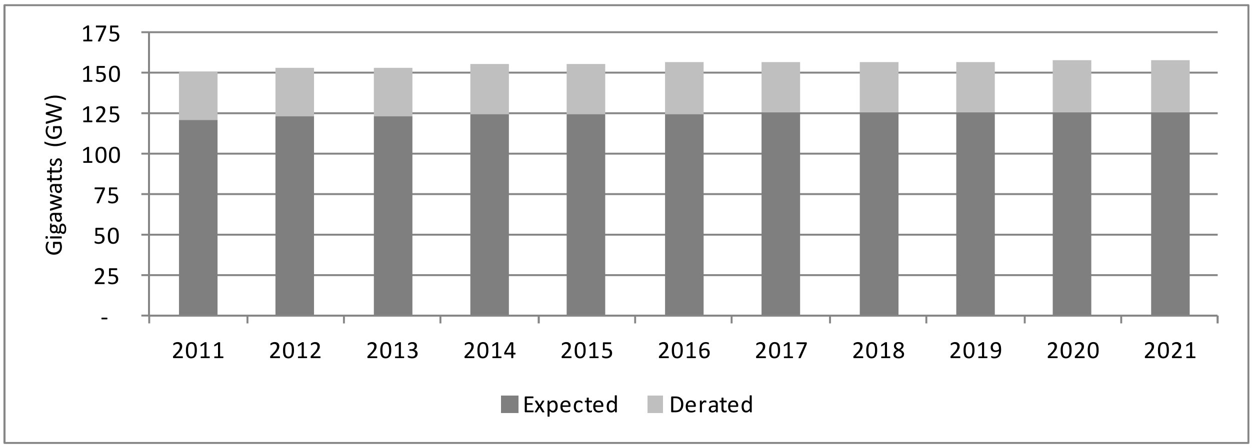
Hydro-powered generation plants (excluding pumped storage) are located primarily in Manitoba-Hydro, Quebec, Ontario British Columbia (WECC-BC), and the Northwest (WECC-NW), where hydro resources account for a major portion of the generation mix in these Assessment Areas. In Canada, the British Columbia and Hydro Quebec subregions relies on hydroelectric generation for 90 and 95 percent of energy production, respectively.

Conventional hydroelectric generation has the advantage of storing energy (in large reservoirs behind the dam wall), however, these facilities can be damaging to fish and aquatic systems and therefore, some units are categorized as non-renewable resources. Alternatively, most run-of-river facilities are considered renewable, with the disadvantage of less controllable generation output, which can be negatively impacted by drought conditions and other weather-related events. Regardless of the specific type of facility, actual output will always fluctuate on a seasonal basis, due to variation in the amounts of rain or snowfall occurring in watersheds where major hydroelectric dams are located

NERC-wide nameplate hydroelectric capacity is projected to remain near the existing 150 GW (Figure 31), with any potential growth mostly resulting from upgrades to maximize the output of existing facilities. The NERC Reference Reserve Margin level is typically lower for Assessment Areas that rely heavily on hydroelectric resource, due to lower forced-outage rates associated with these units.

[53] *Existing-Certain*, *Existing-Other*, *Future-Planned* and *Future-Other* (excludes Conceptual)

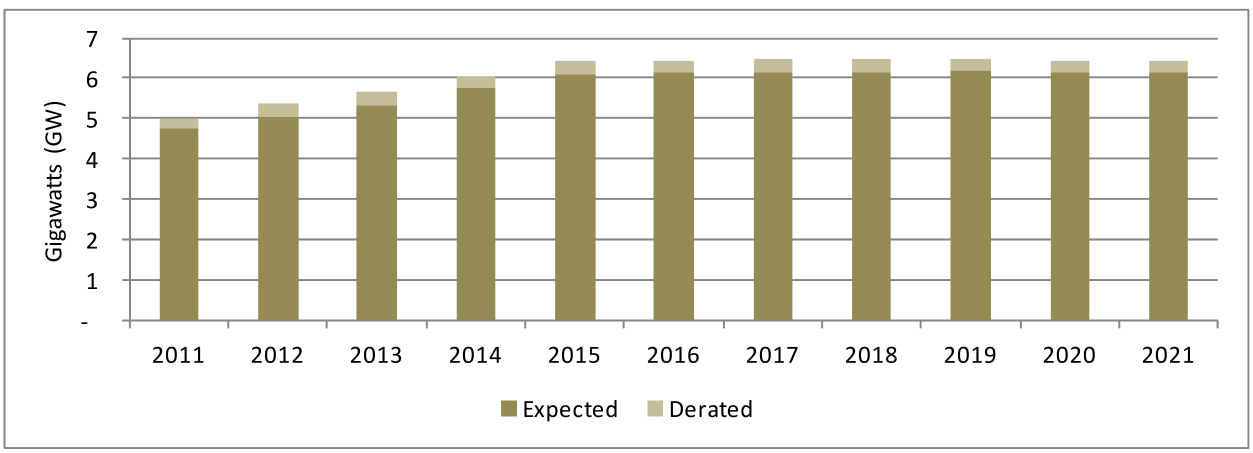
Figure 31: NERC-Wide Projected Hydro Capacity[54]



Biomass

Biomass, or "bioenergy," includes generation from organic, nonfossil material of biological origin, constituting a renewable energy source.[55] Specific fuel sources include wood, plants, crops agricultural residues, oil-rich algae, and other organic components of municipal and industrial waste (including landfill gases).[56] Biomass generation has less variability compared to most other renewables and will continue to grow as a contributor in complying with state Renewable Portfolio Standards (RPS) and other regulations. Nameplate biomass generation will grow from 5,000 MW in 2011 to nearly 6,500 MW in 2016 (Figure 32), with most growth occurring in FRCC, SaskPower, Ontario, SERC-SE, PJM, and WECC-NW Assessment Areas.

Figure 32: NERC-Wide Projected Biomass Capacity[57]



[54] *Existing-Certain*, *Existing-Other*, *Future-Planned* and *Future-Other* (excludes Conceptual).

[55] http://www.eia.gov/tools/glossary/index.cfm?id=B.

[56] http://www.nrel.gov/learning/re_biomass.html.

[57] *Existing-Certain*, *Existing-Other*, *Future-Planned* and *Future-Other* (excludes Conceptual).

Transmission

The future reliability of the bulk power system is largely dependent on the ability to site, permit, and build new transmission assets in a timely manner. The existing electric transmission systems and planned additions over the next 10-years appear adequate to reliably meet customer electricity requirements. However, delays to transmission construction due to permitting and siting have been observed and continue to inhibit the industry from constructing new and potentially vital transmission infrastructure. While these deferments do not currently pose a reliability concern, the importance of a secure transmission infrastructure is amplified when considering the significant addition of variable generation resources, pending environmental legislation in both the United States and Canada, and increased demand projections throughout North America in the assessment's 10-year horizon. It is important that Local, State, Provincial and Federal regulators work together to develop timely and effective solutions to resolve siting and permitting issues.

Stakeholders within the electric industry continually assess the ability of their internal transmission system and interconnections with other systems to meet not only Regional requirements but also compliance with NERC Reliability Standards. Once a set of transmission alternatives has been identified, the project can take up to ten or more years to complete from project identification to final certification and energization of elements. A majority of the time in this process is devoted to the siting, permitting, and land acquisition process, which has no definitive time frame and can vary greatly depending on the geographic location of proposed additions.

In the U.S., the recent issuance of FERC Order 1000[58] reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. While the rule provides a framework for cost allocation and requires certain considerations that need to be addressed, in terms of enhancing reliability, the potential benefit the order brings is in its inter-regional transmission planning reform. While many Regions already, perform inter-regional planning, the order facilitates the acknowledgement of large, interconnection-wide issues by the Federal government.

Planned Transmission Additions

Transmission circuit-mile additions projected for the future are an indicator of the relative strengthening of the existing bulk power transmission system. Significant transmission additions are planned for the long-term time frame in North America (Table 4).[59] Although the addition of transmission circuit-miles is encouraging, the associated increased use of transmission systems due to increased demand growth, generation additions (including geographically distant generation), generation deficiencies, and the increasingly competitive bulk power market must also be considered in the evaluating overall system strength and reliability.

[58] FERC Order No. 1000: http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

[59] Refer to Appendix XX for a detailed listing of Projected Transmission and Transformer Additions for 2011 through 2021.

Table 4: Circuit Mile Line Additions by Assessment Area[60,61]

Country / Assessment Area	Existing	Under Construction	2011-2015		2016-2021		Total Existing, Under Construction, and Planned Additions
	2010	2011	Planned	Conceptual	Planned	Conceptual	2021
ERCOT	29,107	486	5,666	-	496	-	35,755
FRCC	11,973	45	240	-	134	11	12,392
MISO	50,144	33	805	141	255	1,050	51,237
MRO-MAPP	10,314	75	574	-	-	-	10,964
NPCC-New England (ISO-NE)	8,496	182	342	180	35	16	9,056
NPCC-New York (NYISO)	10,990	-	14	-	12	-	11,016
PJM	53,079	271	1,192	520	54	236	54,596
SERC-E	21,995	213	130	81	164	276	22,502
SERC-N	21,303	96	654	11	22	29	22,075
SERC-SE	27,316	114	263	69	336	34	28,029
SERC-W	13,604	127	114	33	70	41	13,915
SPP	32,857	181	1,961	264	216	180	35,215
WECC-US	103,371	495	5,879	2,089	2,404	2,900	112,149
TOTAL-UNITED STATES	**394,549**	**2,318**	**17,833**	**3,388**	**4,199**	**4,773**	**418,900**
MRO-Manitoba Hydro	7,295	-	435	-	1,051	80	8,780
MRO-SaskPower	4,997	-	149	40	-	96	5,146
NPCC-Maritimes	5,056	-	39	13	-	203	5,095
NPCC-Ontario (IESO)	17,713	218	-	180	-	283	17,931
NPCC-Québec	23,100	232	268	291	146	238	23,746
WECC-CAN	21,489	17	2,196	-	645	-	24,347
TOTAL-CANADA	**79,650**	**467**	**3,086**	**524**	**1,842**	**900**	**85,045**
TOTAL-MÉXICO	**1,425**	**-**	**163**	**-**	**52**	**-**	**1,640**
TOTAL-NERC	**475,624**	**2,785**	**21,083**	**3,912**	**6,093**	**5,673**	**505,585**

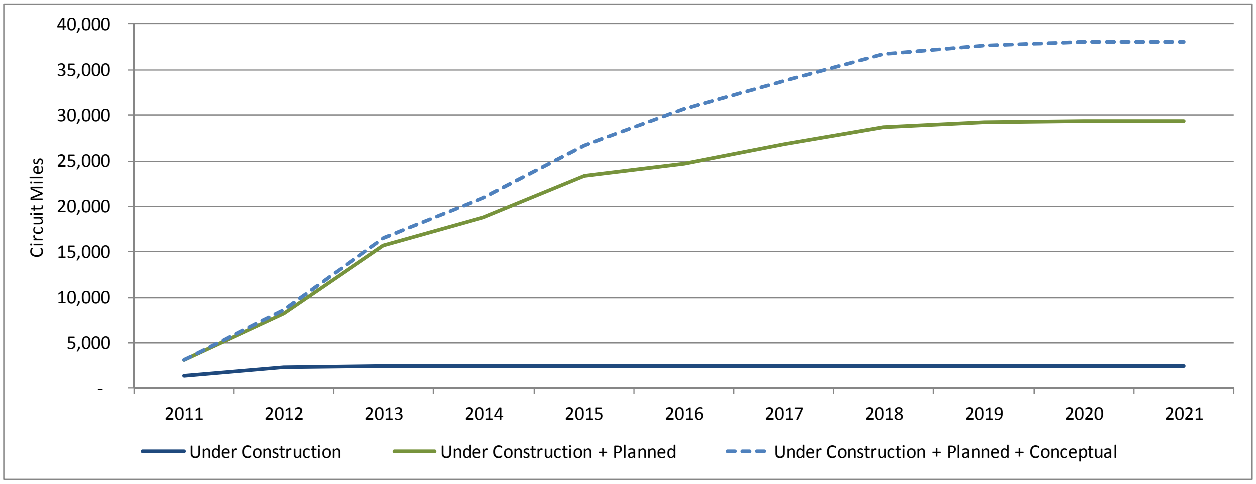
From 2010 through 2021, approximately 38,900 circuit miles of new high-voltage (greater than 100 kV) transmission additions are projected, which is slightly lower than the prior-10-year projection.[62] Of this amount, approximately 30,000 circuit miles are either Under Construction or Planned – the remaining 8,900 miles are considered to be *Conceptual* projects (Figure 33). The most notable five-year increase in transmission is seen in ERCOT, with a 19 percent increase between 2010 and 2015 representing substantial efforts to integrate large amounts of variable generation located in remote locations. ERCOT also reported approximately 650 circuit-miles of new or rebuilt 345 kV transmission lines since 2010.

[60] Total Existing, Under Construction, Planned Line Additions by 2021.

[61] ISO-NE did not include 100-120 kV lines in prior Long-Term Reliability Assessments.

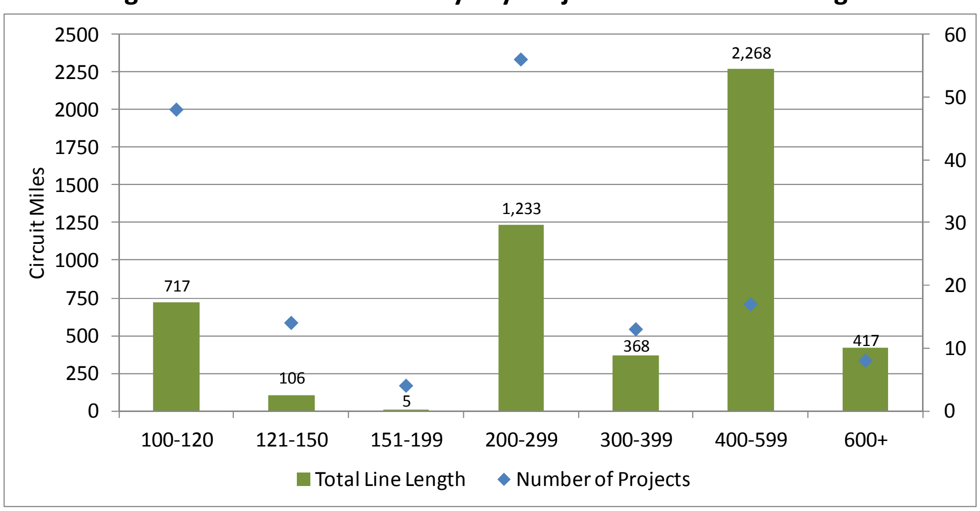
[62] In the 2010 Long-term Reliability Assessment, for the 2010-2019 time period, approximately 39,400 of new transmission was projected.

Figure 33: Transmission Circuit Mile Line Additions by Project Status[63]



For this assessment, NERC collected information from each Assessment Area identifying transmission project delays. Across North America, over 5,100 circuit miles are currently considered delayed.[64] While a majority of the delays in transmission projects are observed at the 400 to 599 kV class (approximately 2,260 circuit miles), less than 20 projects are included in this voltage class (Figure 34). Approximately 70 projects at the 100 to 199 kV class, totaling less than 900 circuit miles, are currently delayed. Because these lower voltage lines are typically built in less rural areas, siting and permitting issues may present more of a challenge.

Figure 34: Transmission Delays by Project and Total Line Length



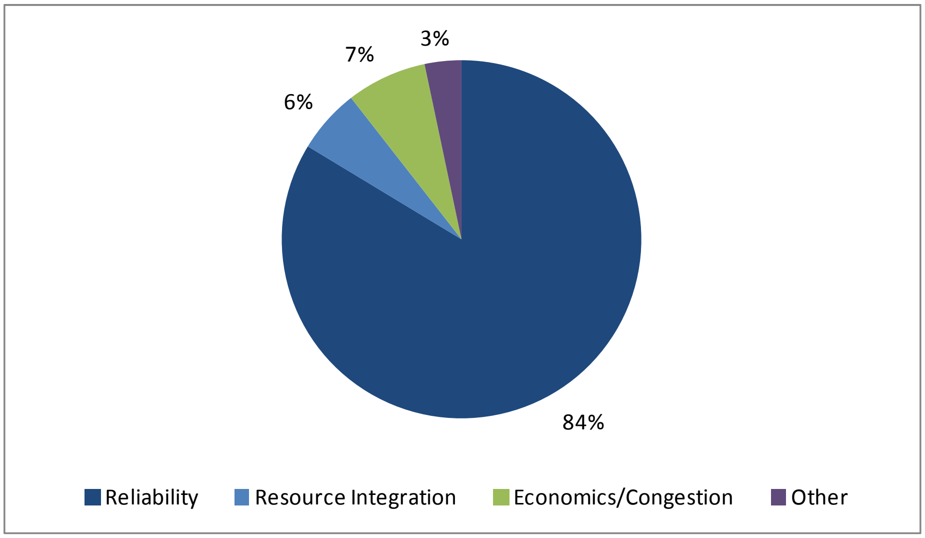
Along with increased granularity on the status of transmission plans, NERC gathers information on key drivers of individual transmission line and infrastructure development projects. Bulk power system reliability was the dominant reason for the addition of new transmission and upgrades of existing

[63] Total AC and DC lines above 100 kV; lines represent a cumulative value for each year.

[64] The total of circuit miles reported as delayed to NERC by Assessment Area is 5,114 miles.

transmission infrastructure (Figure 35). Of the total circuit miles categorized as Under Construction, Planned, and *Conceptual* projects, 84 percent of relative transmission mile additions of greater than 100 kV are needed for reliability purposes, 7 percent are needed to address economic and congestion issues, with the final 9 percent split between integrating new resources and other unidentified conditions.

Figure 35: Drivers for New Transmission



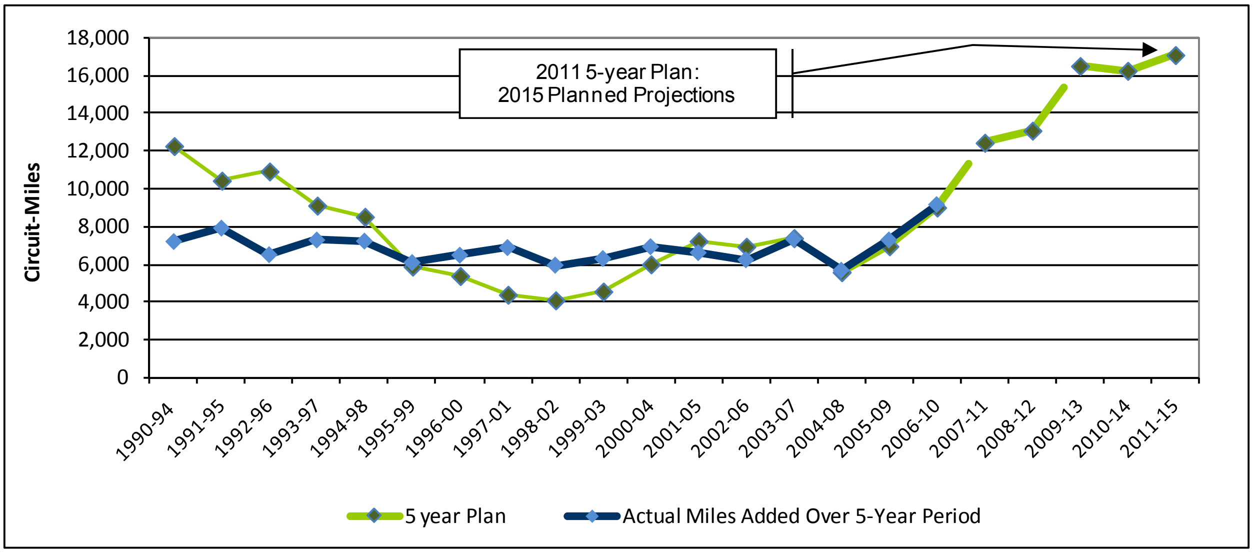
NERC continues to monitor the progress of transmission projects across North America. While transmission planning is dynamic (*i.e.*, project is needed one year, but can be deferred due to a change in demand forecasts), plans should reflect realistic expectations in order to reliably support system needs in the future. For example, ERCOT plans to install a significant amount of transmission circuit miles by 2013. Once in-service, these lines will provide ERCOT with better methods to manage existing and potential congestion problems and will support recently completed Competitive Renewable Energy Zone projects (CREZ) in Western Texas. Large transmission line additions and upgrades are also projected within the MISO footprint, with more than half of these upgrades resulting from a need to reliably integrate renewable generation resources. Minor additions are expected throughout the MRO Assessment Areas to integrate hydropower resources in Manitoba, and improve reliability in the MAPP Assessment Area, while accommodating for projected load growth in SaskPower.

An analysis of the past 15 years shows that additional transmission (greater than 200 kV)[65] during the next five years would nearly triple the average miles that has historically been constructed during a five-year period (Figure 36). Through the period of this analysis, actual miles constructed over five-year periods have roughly averaged 6,500 circuit-miles. During the next five years, about 17,000 miles are categorized as *Future-Planned*, significantly exceeding historical averages. However, during the previous four five-year periods (2003-07 through 2006-10), industry was successful in meeting its projections. From 2006 through year-end 2010, the industry exceeded the average, constructing the most

[65] Transmission data prior to 2009 is limited to 200 kV and above.

transmission during a five-year period since the 1991 through 1995 five-year period.[66] With the beginnings of an observable upward trend, transmission permitting, siting, and construction must continue as planned.

Figure 36: Historical Actual Miles Added for Rolling 5-Year Periods and Projected 5-Year Plans[67]



KEY FINDINGS - TRANSMISSION

Transmission growth is responding to increased plans for integrating and delivering new resources (*i.e.,* renewables); constructed transmission is on pace with projections.

66 1990 is the first year this type of data was digitized. Prior years data did not collect data on 5-year plans.

67 Transmission line operating voltage of 200 kV and greater.

Operational Issues

Resource Management

Ancillary services are a vital component of balancing supply and demand and maintaining reliability of the bulk power system. For a number of years, organizations have taken advantage of the benefits from aggregating demand, provisioning of ancillary services from other jurisdictions, and the operation of interconnected systems. Individual balancing areas[68] with smaller generation and load profiles have a more complex task to balance generation to the variability of demand. Large balancing areas, with sufficient transmission and generation proportional to load require relatively less system balancing as they have more regulation and ramping capability available compared to small balancing areas. However, smaller balancing areas can participate in wide-area arrangements for ancillary services to meet NERC's Control Performance Standards (CPS1 and CPS2).[69]

Larger balancing areas or those participating in wide-area arrangements can offer participants reliability benefits while integrating large amounts of variable generation (*e.g.,* resources such as wind and solar). Additional benefits may be gained through this consolidation of risk and resources, such as increasing the geographic diversity of variable generation resources, access to larger amounts of dispatchable resources, and increasing the flexibility of the system with new generation resources or demand-side resources. Balancing areas should evaluate the enhanced reliability and the potential associated economic benefits resulting from consolidation or participating in wide-area arrangements such as ACE sharing (such as WECC's ACE Diversity Interchange)[70] or wide-area energy management systems.

In many locations throughout North America, balancing area energy transactions are scheduled on an hourly basis. With the advent of variable generation, more frequent and shorter duration scheduling intervals for energy transactions may assist in the large scale integration of variable generation resources to the bulk power system. Balancing areas that schedule energy transactions on an hourly basis must have sufficient regulation based resources to maintain the schedule for each hour. If schedule windows or intervals are reduced to a shorter time horizon, such as 15 minutes, dispatched generators in adjacent balancing areas can provide the necessary ramping capability through an interconnection.[71] With adequate transmission capacity, larger balancing areas and more frequent scheduling within and between areas provide more sources of flexibility for the system to withstand and recover from events.

As total wind generation continues to increase in a number of the Assessment Areas, system operators must ensure that the potential challenges of variability are offset by the availability of conventional

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[68] The NERC Functional Model, Version 5, specifies the type of stakeholders classified as Balancing Areas: http://www.nerc.com/page.php? cid=2%7C247%7C108.

[69] http://www.nerc.com/docs/oc/rs/cpsfaq.pdf, and http://www.nerc.com/files/BAL-001-0_1a.pdf.

[70] http://www.wecc.biz/committees/StandingCommittees/MIC/102908/Lists/Presentations/1/3%20ADI_WECC_103008%20(2).ppt.

[71] Reducing scheduling intervals would also produce a system response more closely aligned with real-time events and provide closer to real-time market data for providers of Demand Response services.

units. Despite challenges for operators in forecasting the amounts of wind production, it is still necessary to ensure the economical and secure operation of the bulk power system. For example:

- SaskPower has noted the benefits of forecasting along with internal unit commitment tools that allow system operators to improve wind resource management.
- The SPP Wind Integration Task Force recently completed a report that found the Regional Transmission Operator (RTO) could potentially absorb wind energy penetration levels of up to 20 percent.[72] However, this can only be accomplished with significant improvements in both transmission and wind forecasting tools. The report also introduced new efforts to obtain and implement a Region-wide wind forecasting tool.
- MISO continues efforts to improve its ability to mitigate issues related to adverse conditions through fostering a solid relationship with open communications between the Regional Balancing Authorities. A shared understanding of the policies, combined with procedural tools is also essential in supporting Regional reliability. Finally, the MISO continues to host several events involving working groups and committees to further advance the knowledge base and expertise in planning strategies for subsequent seasons.

With legislation, regulations, and incentives supporting the construction of renewable resources (such as wind, solar, and hydro), Demand Response may also be used to provide ancillary services to system operators. Demand Response not only provides a mechanism for system operators to manage peak demand (through load reduction), but also increases operational flexibility by providing ancillary services and contributing to operating reserve portfolios on a daily and real-time basis. For Demand Response to be a viable option, operators will require the same certainty as traditional generation resources such as fossil fired or nuclear assets. For Spinning Reserves, Direct Control Demand Response can be a viable option, providing a push-of-the-button dispatch of resources to control room operators. Non-Spinning Reserves have less stringent performance criterion, permitting other varieties of Demand Response to participate. In some Assessment Areas, Energy-Voluntary Demand Response can also be used by system operators in Emergency Situations. Though voluntary, requests through Public Appeals or certain program offerings are also used to reduce peak demand and provide system operators a release valve which can be implemented during periods of capacity constraints. However, these values are not included in this reliability assessment for capacity, as these Demand Response programs (such as Public Appeals) are voluntary in participation.

Transmission Operations

A number of factors over the past few years have contributed to operating transmission at higher loaded levels for longer periods of time. This increased loading is the result, in part, of accessing and delivering economically priced electric energy and capacity to demand, thus achieving higher operating efficiency. System operators must also strictly adhere to operating procedures as transmission systems are loaded at higher rates. However, as the transmission system is operated at increased loading levels, the flexibility and resiliency of the transmission system to successfully accommodate a severe

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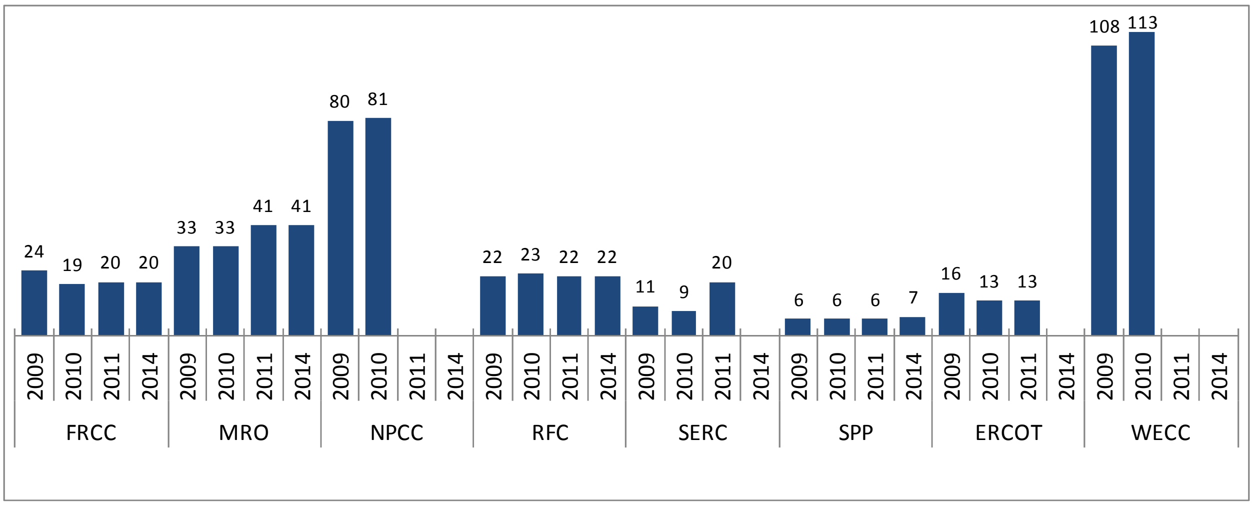
[72] SPP WITF Final Report: http://www.spp.org/publications/2010.zip.

disturbance may diminish.[73] Overlapping forced outages of multiple transmission assets during heavy loading or peak demand may result in interruption of electric service. Even when systems are dispatched and prepositioned to meet NERC Reliability Standards, increased transmission loading (beyond established normal operating limits during emergencies) can leave transmission systems exposed to a wide-range of operating conditions, and on rare occasions, these systems may be pushed beyond their limits by unforeseen events.

Some Regions continue installing special protection systems (SPS) and Remedial Action Schemes (RAS). Specifically, WECC plans to increase the transmission system potential, while meeting NERC Reliability Standards and operating procedures and criteria. ERCOT also has plans for one additional SPS, while retiring four others during the planning period. NERC-wide existing and projected installations of transmission constraint mitigation tools are included below (Figure 37).

Figure 37: NERC-Wide Historic and Planned SPS/RAS[74]



Extreme Conditions

Extreme system conditions can be spurred by more probable extreme conditions which are studied, but not necessarily planned and designed to withstand[75] or by High-Impact, Low-Frequency (HILF) events,

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[73] A severe disturbance could be a contingency that meets or exceeds the N-1 planning criteria, such as the loss of multiple transmission elements in a close geographic area.

[74] Figure includes all available information collected as of June, 2011. 2014 projections have not been submitted by NPCC, SERC, ERCOT, or WECC. 2011 existing data has not been received from NPCC or WECC.

[75] Extreme weather causing higher than expected demands, or loss of multiple bulk power system elements: http://www.nerc.com/files/TPL-003-1a.pdf.

NERC Reliability Standards dictate a layer of protection in transmission planning—utility planners must look at adding system backup, or robustness, to cover a scenario called a "single contingency situation" such as the failure of a transformer or other significant event that causes the outage of a transmission line or large generator. These single contingency scenarios are known as "N-1" (N minus one) conditions. The general philosophy is that no single failure of a piece of equipment connected to or comprising the transmission network should cause a large number of customers to lose power. Transmission designers further test the system design by looking at scenarios involving two or more equipment failures (known as "N minus one minus one" scenarios or "N-1-1"). To recognize the specific regional attributes of its transmission grid, some operation and planning areas require additional planning standards. For example, some systems must be designed so that it can handle electric demand under extreme weather conditions (often referred to as a "90/10 load"), the

Footnote Continued on Next Page

described in the *Emerging and Standing Reliability Issues* section of this report. Although each NERC Region is inherently different, many share similar operating challenges from season-to-season and year-to-year. Sharing these experiences and subsequent lessons learned with the industry can be helpful in developing solutions to mitigate or otherwise prevent future reliability issues. NERC continues to monitor the progress of implementing lessons learned into future year preparations. Lessons learned through the assessment of actual operating experiences may also be included in *NERC Event Analysis: Lessons Learned* documents,[76] which are targeted to focus on gaining value from such information.

Most recently, the ERCOT Region encountered significant challenges on one day during the 2010/2011 winter season, although not during the winter peak day. February had record-breaking winter demand levels on two different occasions as temperatures hit twenty-year lows. On February 2, 2011, ERCOT experienced an Energy Emergency Alert (EEA) Level 3 event that led to the request to shed 4,000 MW of Firm load. An in-depth report on this event by NERC and FERC was released in August 2011.[77]

The February 2, 2011 EEA event was primarily caused by the unavailability of resources due to the freezing of instrumentation and sensing lines during extreme weather events, along with gas well-head freezing. Generation in the ERCOT Region is required by the Public Utility Commission of Texas Substantive Rule §25.53 to have weatherization plans.[78] Most generating units in the Region were designed for performance during extreme hot temperatures during the summers, but designs generally should have been able to handle the low temperatures encountered. Over 150 generators faced difficulties operating in the below-freezing temperatures which were combined with the high wind chill factors that occurred on February 2, 2011. As a result of these experiences, many weatherization issues were immediately addressed to prevent a recurrence the following week when similar weather conditions caused the Region's seasonal peak on February 10, 2011.

The most significant challenge in ERCOT during the 2010/2011 winter period was managing the sudden unavailability of large amounts of generation within a short time frame during high demand conditions. Multiple forced generator outages required swift action, including the deployment of Controllable Load resources and Emergency Interruptible Load Services combined with shedding Firm load to protect the integrity of the ERCOT grid.

The ERCOT Region plans to complete the following action items, in response to this event:

Continued Footnote:

outage of the two most critical generators, and/or limitations on the use of fossil fuel-fired peaking generation units. By using these and other criteria to plan and design the generation and transmission system, transmission utilities seek to ensure that customers rarely lose power because of a problem on the bulk power system. Most customer outages are caused by a local problem on the distribution system such as a tree coming in contact with an overhead wire.

76 NERC Events Analysis: Lessons Learned http://www.nerc.com/page.php?cid=5|385.

77 Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011: http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf and Analysis of Power System Impacts and Frequency Response Performance of the February 1-5, 2011 Event: http://www.nerc.com/files/RISA%20Cold%20Snap%20report%20 September%202011.pdf.

78 http://puc.state.tx.us/agency/rulesnlaws/subrules/electric/25.53/25.53.pdf.

- **Power Plant Weatherization**: ERCOT will initiate and participate in discussions related to the adequate weatherization of generation units. This includes reviews of plant procedures, training programs for severe weather and winter weather events, and availability of resources in response to winter weather events.
- **Load Shed Management:** ERCOT will work with transmission providers to study the potential use of Advanced Metering Infrastructure (AMI) capabilities in selective load reduction. In addition, increased collaboration will occur between transmission and distribution providers to review existing public policy, bulk power system needs (including natural gas supply points), and practical considerations regarding the management of critical loads.
- **Fuel Supply Issues:** Although fuel-related issues were very limited during the February 2, 2011 event, ERCOT plans to work with state agencies to examine the coordination of natural gas supply and transportation issues, specifically regarding the management of the electrical grid.
- **Communications:** ERCOT will review and update communication policies and procedures related to grid emergencies with regulatory agencies, Registered Entities, and the media. Additionally, a long-term transmission proposal provided by Transmission Operators to provide additional import capabilities in response to the lower Rio Grande Valley load shed event of February 3-4, 2011 is under review.

Undoubtedly, this significant event will shape the way ERCOT plans and operates their system in the future. More importantly, other Assessment Areas are considering these lessons in their preparations for similar conditions.

Estimated Demand, Resources, and Reserve Margins

Demand

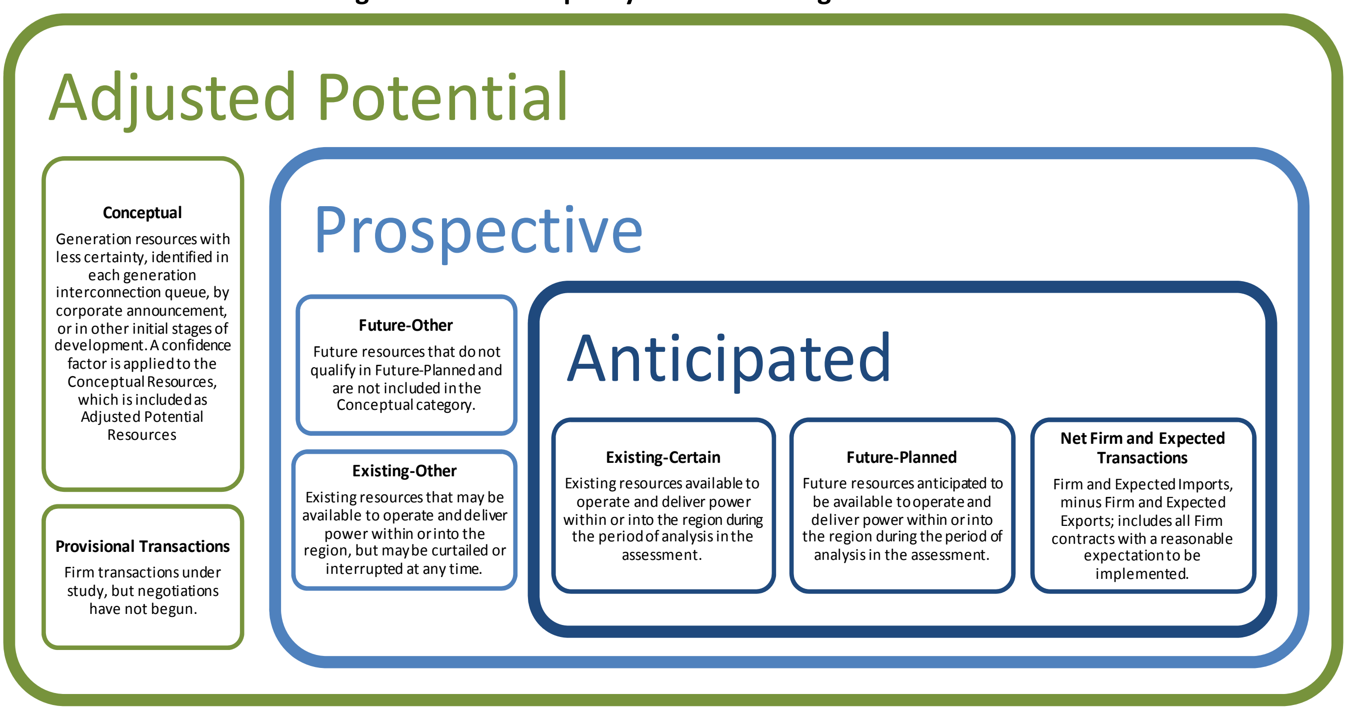
NERC uses the following terms to categorize on-peak electricity demand:

- **Total Internal Demand** — The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.
- **Net Internal Demand (MW)** — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

Capacity Resources

NERC uses the following terms to categorize capacity resources and transactions throughout this report. These capacity categories are then used to calculate estimated Planning Reserve Margins for each NERC Assessment Area (Figure 38).

Figure 38: NERC Capacity Resource Categories[79]



79 See section entitled *Reliability Concepts Used in this Report* for more detailed definitions.

Reserve Margins

Planning Reserve Margins, developed for this analysis, are categorized based on certainty that future resources expected to be available to delivery power within the assessment time frame are actually constructed and deployed. A consistent method of calculating Reserve Margins (initially introduced in the *2011 Summer Reliability Assessment*) will be used in this assessment and in subsequent NERC reports. This accurately accounts for Controllable Capacity Demand Response (CCDR) as a supply-side resource.[80] A comparison of the pre-2011 to the revised method is presented below (Table 5).

Table 5: Enhancements to Reserve Margin Calculations (Pre-2011 vs. 2011)

Pre-2011 Reserve Margin Calculation (Majority)	2011 Reserve Margin Calculation
$RM = \frac{[(Capacity - (Total\ Internal\ Demand - CCDR)]}{(Total\ Internal\ Demand - CCDR)}$	$RM = \frac{[(Capacity + CCDR) - (Total\ Internal\ Demand)]}{(Total\ Internal\ Demand)}$

Reserve Margins are capacity-based metrics and do not provide a comprehensive assessment of performance in energy-limited systems (*e.g.,* hydro capacity with limited water resources or systems with significant variable generation). Each capacity resource category (identified and explained in the previous section) is also used to calculate each different planning Reserve Margin. Consider the following examples (Table 6).

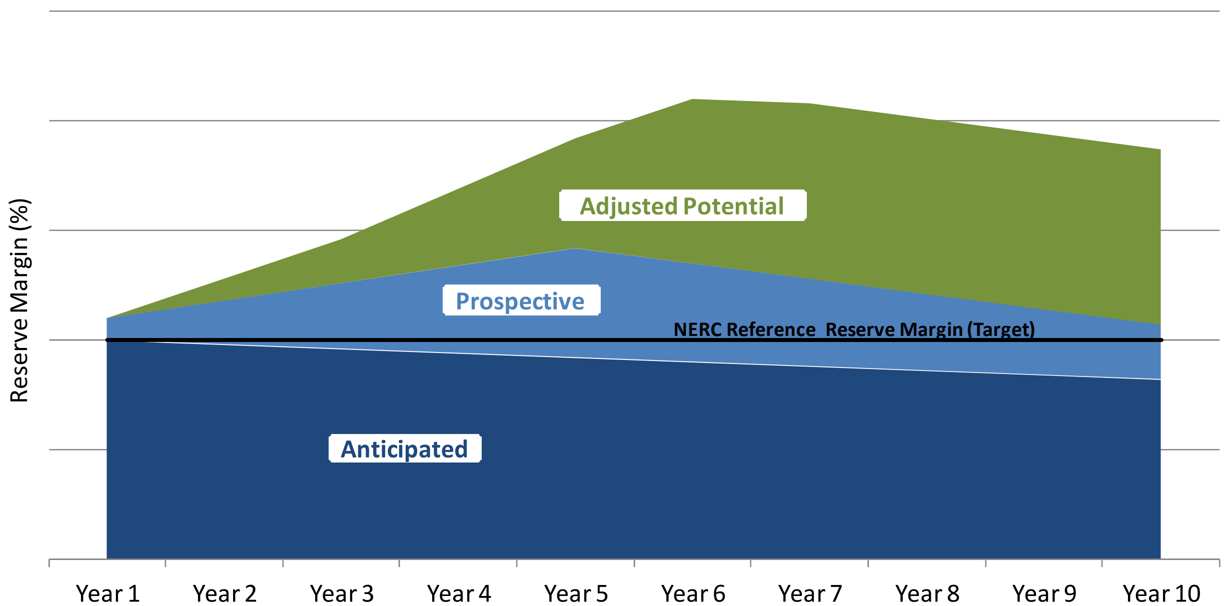
Table 6: Anticipated, Prospective, and Adjusted Potential Reserve Margin Calculations

Reserve Margin	Calculation
Anticipated	$RM = \frac{[(Anticipated\ Capacity\ Resources) - (Total\ Internal\ Demand)]}{(Total\ Internal\ Demand)}$
Prospective	$RM = \frac{[(Prospective\ Capacity\ Resources) - (Total\ Internal\ Demand)]}{(Total\ Internal\ Demand)}$
Adjusted Potential	$RM = \frac{[(Adjusted\ Potential\ Capacity\ Resources) - (Total\ Internal\ Demand)]}{(Total\ Internal\ Demand)}$

Planning Reserve Margins for each Assessment Area are compared to the NERC Reference Margin Level (Target) which is usually defined and provided by each NERC Region or subregion. In the absence of a defined Reserve Margin Target, NERC assigns a 15 percent Reserve Margin Target for predominately thermal systems and 10 percent for predominately hydro systems. This Target then serves as a bass for determining whether more resources (*e.g.,* generation, Demand-Side Management, transfers) may be needed within that Region/subregion.

[80] This change was recommended by the NERC Resources Issues Subcommittee under the direction of the NERC Planning Committee. The recommendation was approved by the NERC Planning Committee in 2010 and is detailed in the report titled *Recommendations for the Treatment of Controllable Capacity Demand Response programs in Reserve Margin Calculations,* June 2010: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

Figure 39: NERC Reserve Margin Example



Projected Reserve Margins, including both summer and winter seasons from 2011 through 2021, are shown on the following pages (Table 7 through Table 28). The following notes provide additional clarification.

Note 1: Demand and Supply forecasts were reported between February and August, 2011—depending on the Assessment Area.

Note 2: Values for both Total Internal Demand and Net Internal Demand for each Assessment Area represent on-peak projections for the given season.

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

Note 4: The winter demand data collected for this long-term assessment and reflected in the following tables may be slightly different when compared to the NERC *2011 Winter Reliability Assessment* (to be published shortly after the release of this report) due to the timing of data collection for each assessment.

Table 7: Demand, Resources, and Reserve Margins – Summer 2011

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	63,770	62,286	74,683	74,683	74,692	17.1%	17.1%	17.1%	13.75%
FRCC	46,091	42,945	56,684	56,861	56,861	23.0%	23.4%	23.4%	15.0%
MISO	98,068	90,249	119,764	136,872	136,872	22.1%	39.6%	39.6%	15.0%
MRO-MAPP	4,810	4,704	6,900	6,900	6,900	43.5%	43.5%	43.5%	15.0%
NPCC-New England (ISO-NE)	27,550	25,515	32,761	34,988	35,017	18.9%	27.0%	27.1%	15.0%
NPCC-New York (NYISO)	32,712	30,659	43,269	43,269	43,271	32.3%	32.3%	32.3%	15.5%
PJM	148,941	137,341	193,340	193,340	194,195	29.8%	29.8%	30.4%	15.0%
SERC-E	43,249	41,554	53,598	53,598	53,598	23.9%	23.9%	23.9%	15.0%
SERC-N	46,846	44,931	59,245	59,760	59,760	26.5%	27.6%	27.6%	15.0%
SERC-SE	49,314	47,610	61,283	64,584	64,584	24.3%	31.0%	31.0%	15.0%
SERC-W	25,101	24,228	35,204	38,747	38,747	40.2%	54.4%	54.4%	15.0%
SPP	53,084	51,783	67,524	71,942	71,942	27.2%	35.5%	35.5%	13.6%
WECC-BASN	14,269	13,219	17,071	17,071	17,095	19.6%	19.6%	19.8%	12.6%
WECC-CALN	25,116	24,258	32,667	32,667	32,519	30.1%	30.1%	29.5%	14.2%
WECC-CALS	32,661	31,055	48,117	48,117	48,117	47.3%	47.3%	47.3%	14.9%
WECC-DSW	28,308	27,848	35,171	35,171	35,172	24.2%	24.2%	24.2%	13.5%
WECC-NORW	24,610	24,605	33,825	33,825	33,825	37.4%	37.4%	37.4%	17.2%
WECC-ROCK	10,973	10,576	14,485	14,485	14,565	32.0%	32.0%	32.7%	12.5%
TOTAL-UNITED STATES	**775,472**	**735,365**	**985,592**	**1,016,882**	**1,017,733**	**27.1%**	**31.1%**	**31.2%**	**15.0%**
MRO-Manitoba Hydro	3,167	2,940	4,497	4,497	4,497	42.0%	42.0%	42.0%	12.0%
MRO-SaskPower	3,045	2,954	3,589	3,589	3,589	17.9%	17.9%	17.9%	13.0%
NPCC-Maritimes	3,604	3,202	6,584	6,584	6,584	82.7%	82.7%	82.7%	20.0%
NPCC-Ontario (IESO)	23,539	22,373	30,259	30,259	30,265	28.5%	28.5%	28.6%	21.3%
NPCC-Québec	20,930	20,930	31,620	31,620	31,620	51.1%	51.1%	51.1%	9.7%
WECC-AESO	9,632	9,579	12,741	12,741	12,756	32.3%	32.3%	32.4%	12.3%
WECC-BC	8,403	8,350	9,960	9,960	10,561	18.5%	18.5%	25.7%	12.3%
TOTAL-CANADA	**72,319**	**70,328**	**99,249**	**99,249**	**99,872**	**37.2%**	**37.2%**	**38.1%**	**10.0%**
TOTAL-MÉXICO	**2,190**	**2,190**	**2,962**	**2,962**	**2,962**	**35.3%**	**35.3%**	**35.3%**	**11.9%**
TOTAL-NERC	**849,981**	**807,883**	**1,087,804**	**1,119,093**	**1,120,567**	**28.0%**	**31.7%**	**31.8%**	**15.0%**
EASTERN INTERCONNECTION	**609,120**	**572,988**	**774,502**	**805,791**	**806,683**	**27.2%**	**32.3%**	**32.4%**	**15.0%**
ERCOT INTERCONNECTION	**63,770**	**62,286**	**74,683**	**74,683**	**74,692**	**17.1%**	**17.1%**	**17.1%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,930**	**20,930**	**31,620**	**31,620**	**31,620**	**51.1%**	**51.1%**	**51.1%**	**9.7%**
WESTERN INTERCONNECTION	**149,714**	**145,285**	**205,723**	**205,723**	**205,800**	**37.4%**	**37.4%**	**37.5%**	**14.2%**

Table 8: Demand, Resources, and Reserve Margins – Winter 2011/2012

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	51,642	50,158	78,740	78,740	78,749	52.5%	52.5%	52.5%	13.75%
FRCC	47,613	44,196	59,203	59,399	59,399	24.3%	24.8%	24.8%	15.0%
MISO	79,052	71,233	114,870	131,978	131,978	45.3%	67.0%	67.0%	15.0%
MRO-MAPP	5,118	4,746	7,619	7,619	7,619	48.9%	48.9%	48.9%	15.0%
NPCC-New England (ISO-NE)	22,255	20,391	33,196	37,180	37,209	49.2%	67.1%	67.2%	15.0%
NPCC-New York (NYISO)	24,533	24,533	43,614	43,614	43,621	77.8%	77.8%	77.8%	15.5%
PJM	130,711	119,806	193,548	193,548	193,548	48.1%	48.1%	48.1%	15.0%
SERC-E	42,298	41,018	56,280	56,280	56,280	33.1%	33.1%	33.1%	15.0%
SERC-N	47,606	46,154	59,524	60,105	60,105	25.0%	26.3%	26.3%	15.0%
SERC-SE	44,240	42,535	62,620	66,067	66,067	41.5%	49.3%	49.3%	15.0%
SERC-W	20,006	19,283	35,827	39,458	39,458	79.1%	97.2%	97.2%	15.0%
SPP	41,138	40,218	65,393	70,046	70,071	59.0%	70.3%	70.3%	13.6%
WECC-BASN	11,427	11,175	13,900	13,900	13,924	21.6%	21.6%	21.9%	12.6%
WECC-CALN	17,837	17,607	28,577	28,577	28,590	60.2%	60.2%	60.3%	14.2%
WECC-CALS	22,396	21,633	44,333	44,333	44,333	98.0%	98.0%	98.0%	14.9%
WECC-DSW	17,478	17,030	33,706	33,706	33,785	92.9%	92.9%	93.3%	13.5%
WECC-NORW	29,468	29,425	36,879	36,879	36,879	25.1%	25.1%	25.1%	17.2%
WECC-ROCK	9,561	9,320	14,676	14,676	14,678	53.5%	53.5%	53.5%	12.5%
TOTAL-UNITED STATES	**664,378**	**630,461**	**982,506**	**1,016,105**	**1,016,294**	**47.9%**	**52.9%**	**53.0%**	**15.0%**
MRO-Manitoba Hydro	4,517	4,291	5,579	5,579	5,579	23.5%	23.5%	23.5%	12.0%
MRO-SaskPower	3,407	3,316	3,892	3,892	3,892	14.2%	14.2%	14.2%	13.0%
NPCC-Maritimes	5,668	5,298	6,821	6,821	6,821	20.3%	20.3%	20.3%	20.0%
NPCC-Ontario (IESO)	22,495	21,300	29,889	29,889	29,894	32.9%	32.9%	32.9%	21.3%
NPCC-Québec	37,153	35,553	41,436	41,436	41,436	11.5%	11.5%	11.5%	9.7%
WECC-AESO	10,261	10,142	13,557	13,557	13,572	32.1%	32.1%	32.3%	12.3%
WECC-BC	11,106	10,987	13,274	13,274	13,388	19.5%	19.5%	20.5%	12.3%
TOTAL-CANADA	**94,606**	**90,886**	**114,449**	**114,449**	**114,583**	**21.0%**	**21.0%**	**21.1%**	**10.0%**
TOTAL-MÉXICO	**1,458**	**1,458**	**2,630**	**2,630**	**2,635**	**80.4%**	**80.4%**	**80.7%**	**11.9%**
TOTAL-NERC	**760,443**	**722,805**	**1,099,584**	**1,133,184**	**1,133,512**	**44.6%**	**49.0%**	**49.1%**	**15.0%**
EASTERN INTERCONNECTION	**540,656**	**508,317**	**777,876**	**811,475**	**811,543**	**43.9%**	**50.1%**	**50.1%**	**15.0%**
ERCOT INTERCONNECTION	**51,642**	**50,158**	**78,740**	**78,740**	**78,749**	**52.5%**	**52.5%**	**52.5%**	**13.75%**
QUÉBEC INTERCONNECTION	**37,153**	**35,553**	**41,436**	**41,436**	**41,436**	**11.5%**	**11.5%**	**11.5%**	**9.7%**
WESTERN INTERCONNECTION	**129,485**	**127,389**	**194,933**	**194,933**	**195,237**	**50.5%**	**50.5%**	**50.8%**	**15.0%**

Table 9: Demand, Resources, and Reserve Margins - Summer 2012

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	65,406	63,880	76,428	76,428	77,445	16.9%	16.9%	18.4%	13.75%
FRCC	46,658	43,389	57,964	58,160	58,160	24.2%	24.7%	24.7%	15.0%
MISO	92,976	85,157	114,450	131,592	131,592	23.1%	41.5%	41.5%	15.0%
MRO-MAPP	5,036	4,926	7,152	7,152	7,152	42.0%	42.0%	42.0%	15.0%
NPCC-New England (ISO-NE)	28,095	25,489	32,840	36,726	36,827	16.9%	30.7%	31.1%	15.0%
NPCC-New York (NYISO)	33,182	31,129	44,153	44,153	44,156	33.1%	33.1%	33.1%	15.5%
PJM	158,603	151,780	196,424	196,424	199,106	23.8%	23.8%	25.5%	15.0%
SERC-E	44,046	42,102	55,430	55,430	55,430	25.8%	25.8%	25.8%	15.0%
SERC-N	46,923	44,427	60,679	61,204	61,204	29.3%	30.4%	30.4%	15.0%
SERC-SE	50,470	48,642	61,948	65,871	65,871	22.7%	30.5%	30.5%	15.0%
SERC-W	25,588	24,681	34,795	40,900	40,900	36.0%	59.8%	59.8%	15.0%
SPP	53,632	52,337	67,934	72,353	72,358	26.7%	34.9%	34.9%	13.6%
WECC-BASN	14,730	13,681	18,312	18,312	18,336	24.3%	24.3%	24.5%	12.6%
WECC-CALN	25,408	24,510	35,132	35,132	35,165	38.3%	38.3%	38.4%	14.2%
WECC-CALS	33,148	31,057	51,696	51,696	51,849	56.0%	56.0%	56.4%	14.9%
WECC-DSW	28,506	28,003	37,101	37,101	37,240	30.2%	30.2%	30.6%	13.5%
WECC-NORW	24,933	24,911	34,703	34,703	34,708	39.2%	39.2%	39.2%	17.2%
WECC-ROCK	11,161	10,748	15,336	15,336	15,605	37.4%	37.4%	39.8%	12.5%
TOTAL-UNITED STATES	**788,500**	**750,847**	**1,002,476**	**1,038,673**	**1,043,104**	**27.1%**	**31.7%**	**32.3%**	**15.0%**
MRO-Manitoba Hydro	3,194	2,967	4,759	4,759	4,759	49.0%	49.0%	49.0%	12.0%
MRO-SaskPower	3,117	3,026	3,618	3,618	3,618	16.1%	16.1%	16.1%	13.0%
NPCC-Maritimes	3,642	3,265	6,260	6,260	6,260	71.9%	71.9%	71.9%	20.0%
NPCC-Ontario (IESO)	23,712	22,392	30,698	30,698	30,708	29.5%	29.5%	29.5%	21.8%
NPCC-Québec	21,159	21,159	31,862	31,862	31,862	50.6%	50.6%	50.6%	9.8%
WECC-AESO	10,412	10,359	13,483	13,483	13,498	29.5%	29.5%	29.6%	12.3%
WECC-BC	8,221	8,168	9,969	9,969	10,245	21.3%	21.3%	24.6%	12.3%
TOTAL-CANADA	**73,457**	**71,337**	**100,649**	**100,649**	**100,949**	**37.0%**	**37.0%**	**37.4%**	**10.0%**
TOTAL-MÉXICO	**2,281**	**2,281**	**3,085**	**3,085**	**3,085**	**35.2%**	**35.2%**	**35.2%**	**11.9%**
TOTAL-NERC	**864,238**	**824,465**	**1,106,210**	**1,142,407**	**1,147,139**	**28.0%**	**32.2%**	**32.7%**	**15.0%**
EASTERN INTERCONNECTION	**618,874**	**585,709**	**779,103**	**815,299**	**818,100**	**25.9%**	**31.7%**	**32.2%**	**15.0%**
ERCOT INTERCONNECTION	**65,406**	**63,880**	**76,428**	**76,428**	**77,445**	**16.9%**	**16.9%**	**18.4%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,159**	**21,159**	**31,862**	**31,862**	**31,862**	**50.6%**	**50.6%**	**50.6%**	**9.7%**
WESTERN INTERCONNECTION	**151,722**	**146,693**	**224,359**	**224,359**	**224,806**	**47.9%**	**47.9%**	**48.2%**	**14.2%**

Table 10: Demand, Resources, and Reserve Margins - Winter 2012/2013

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	51,343	49,817	79,966	79,966	81,496	55.7%	55.7%	58.7%	13.75%
FRCC	48,276	44,750	60,808	61,003	61,003	26.0%	26.4%	26.4%	15.0%
MISO	75,208	67,389	109,556	126,698	126,698	45.7%	68.5%	68.5%	15.0%
MRO-MAPP	5,066	4,686	7,587	7,587	7,587	49.8%	49.8%	49.8%	15.0%
NPCC-New England (ISO-NE)	22,365	19,944	33,046	38,966	39,067	47.8%	74.2%	74.7%	15.0%
NPCC-New York (NYISO)	24,693	24,693	45,312	45,312	45,432	83.5%	83.5%	84.0%	15.5%
PJM	133,594	127,464	195,907	195,907	195,907	46.6%	46.6%	46.6%	15.0%
SERC-E	42,589	41,133	58,546	58,546	58,546	37.5%	37.5%	37.5%	15.0%
SERC-N	47,514	45,941	62,602	63,191	63,191	31.8%	33.0%	33.0%	15.0%
SERC-SE	45,351	43,521	64,171	68,241	68,241	41.5%	50.5%	50.5%	15.0%
SERC-W	20,664	19,909	35,388	41,668	41,668	71.3%	101.6%	101.6%	15.0%
SPP	41,693	40,693	66,466	71,119	71,164	59.4%	70.6%	70.7%	13.6%
WECC-BASN	11,756	11,484	15,305	15,305	15,329	30.2%	30.2%	30.4%	12.6%
WECC-CALN	18,061	17,824	31,028	31,028	31,041	71.8%	71.8%	71.9%	14.2%
WECC-CALS	22,786	21,586	47,964	47,964	48,117	110.5%	110.5%	111.2%	14.9%
WECC-DSW	17,590	17,316	34,387	34,387	34,854	95.5%	95.5%	98.1%	13.5%
WECC-NORW	29,818	29,768	37,686	37,686	37,687	26.4%	26.4%	26.4%	17.2%
WECC-ROCK	9,706	9,461	16,282	16,282	16,300	67.8%	67.8%	67.9%	12.5%
TOTAL-UNITED STATES	**668,073**	**637,379**	**1,002,006**	**1,040,856**	**1,043,329**	**50.0%**	**55.8%**	**56.2%**	**15.0%**
MRO-Manitoba Hydro	4,559	4,333	5,839	5,839	5,839	28.1%	28.1%	28.1%	12.0%
MRO-SaskPower	3,537	3,446	3,979	3,979	3,979	12.5%	12.5%	12.5%	13.0%
NPCC-Maritimes	5,650	5,280	7,197	7,197	7,197	27.4%	27.4%	27.4%	20.0%
NPCC-Ontario (IESO)	22,242	20,893	33,508	33,508	33,519	50.7%	50.7%	50.7%	21.8%
NPCC-Québec	37,923	36,323	42,837	42,837	42,837	13.0%	13.0%	13.0%	9.8%
WECC-AESO	10,739	10,620	14,536	14,536	14,671	35.4%	35.4%	36.6%	12.3%
WECC-BC	11,152	11,033	13,384	13,384	13,404	20.0%	20.0%	20.2%	12.3%
TOTAL-CANADA	**95,803**	**91,929**	**121,281**	**121,281**	**121,446**	**26.6%**	**26.6%**	**26.8%**	**10.0%**
TOTAL-MÉXICO	**1,519**	**1,519**	**2,910**	**2,910**	**2,910**	**91.6%**	**91.6%**	**91.6%**	**11.9%**
TOTAL-NERC	**765,394**	**730,827**	**1,126,197**	**1,165,046**	**1,167,685**	**47.1%**	**52.2%**	**52.6%**	**15.0%**
EASTERN INTERCONNECTION	**543,001**	**514,076**	**789,912**	**828,762**	**829,039**	**45.5%**	**52.6%**	**52.7%**	**15.0%**
ERCOT INTERCONNECTION	**51,343**	**49,817**	**79,966**	**79,966**	**81,496**	**55.7%**	**55.7%**	**58.7%**	**13.75%**
QUÉBEC INTERCONNECTION	**37,923**	**36,323**	**42,837**	**42,837**	**42,837**	**13.0%**	**13.0%**	**13.0%**	**9.7%**
WESTERN INTERCONNECTION	**131,514**	**129,117**	**212,805**	**212,805**	**213,736**	**61.8%**	**61.8%**	**62.5%**	**15.0%**

Table 11: Demand, Resources, and Reserve Margins - Summer 2013

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	67,362	65,790	76,635	76,635	78,671	13.8%	13.8%	16.8%	13.75%
FRCC	47,446	44,056	58,205	58,401	58,401	22.7%	23.1%	23.1%	15.0%
MISO	94,834	87,015	114,509	131,651	131,651	20.7%	38.8%	38.8%	15.0%
MRO-MAPP	5,331	5,216	7,016	7,016	7,016	31.6%	31.6%	31.6%	15.0%
NPCC-New England (ISO-NE)	28,525	25,522	33,361	37,362	37,726	17.0%	31.0%	32.3%	15.0%
NPCC-New York (NYISO)	33,433	31,380	45,814	45,814	45,960	37.0%	37.0%	37.5%	15.5%
PJM	162,489	153,510	200,244	200,244	203,310	23.2%	23.2%	25.1%	15.0%
SERC-E	44,863	42,840	56,526	56,526	56,526	26.0%	26.0%	26.0%	15.0%
SERC-N	47,359	44,683	61,080	61,605	61,605	29.0%	30.1%	30.1%	15.0%
SERC-SE	51,649	49,727	63,638	66,668	66,668	23.2%	29.1%	29.1%	15.0%
SERC-W	25,912	24,997	34,589	40,882	40,882	33.5%	57.8%	57.8%	15.0%
SPP	55,149	53,802	69,226	73,645	73,665	25.5%	33.5%	33.6%	13.6%
WECC-BASN	15,085	14,010	18,568	18,568	18,654	23.1%	23.1%	23.7%	12.6%
WECC-CALN	25,645	24,734	36,597	36,597	36,551	42.7%	42.7%	42.5%	14.2%
WECC-CALS	33,711	31,355	54,732	54,732	54,932	62.4%	62.4%	63.0%	14.9%
WECC-DSW	28,933	28,416	38,056	38,056	38,908	31.5%	31.5%	34.5%	13.5%
WECC-NORW	25,167	25,127	34,371	34,371	34,376	36.6%	36.6%	36.6%	17.2%
WECC-ROCK	11,409	10,981	16,267	16,267	16,504	42.6%	42.6%	44.7%	12.5%
TOTAL-UNITED STATES	**804,304**	**763,163**	**1,019,434**	**1,055,040**	**1,062,006**	**26.7%**	**31.2%**	**32.0%**	**15.0%**
MRO-Manitoba Hydro	3,252	3,025	4,845	4,845	4,845	49.0%	49.0%	49.0%	12.0%
MRO-SaskPower	3,260	3,169	3,555	3,555	3,555	9.0%	9.0%	9.0%	13.0%
NPCC-Maritimes	3,685	3,310	6,956	6,956	6,956	88.8%	88.8%	88.8%	20.0%
NPCC-Ontario (IESO)	23,257	21,778	30,736	30,736	30,765	32.2%	32.2%	32.3%	18.7%
NPCC-Québec	21,007	21,007	31,966	31,966	31,966	52.2%	52.2%	52.2%	11.6%
WECC-AESO	11,049	10,996	13,807	13,807	14,122	25.0%	25.0%	27.8%	12.3%
WECC-BC	8,217	8,164	10,048	10,048	10,805	22.3%	22.3%	31.5%	12.3%
TOTAL-CANADA	**73,728**	**71,449**	**101,913**	**101,913**	**103,014**	**38.2%**	**38.2%**	**39.7%**	**10.0%**
TOTAL-MÉXICO	**2,392**	**2,392**	**3,369**	**3,369**	**3,399**	**40.8%**	**40.8%**	**42.1%**	**11.9%**
TOTAL-NERC	**880,424**	**837,004**	**1,124,716**	**1,160,322**	**1,168,419**	**27.7%**	**31.8%**	**32.7%**	**15.0%**
EASTERN INTERCONNECTION	**630,446**	**594,031**	**790,300**	**825,906**	**829,532**	**25.4%**	**31.0%**	**31.6%**	**15.0%**
ERCOT INTERCONNECTION	**67,362**	**65,790**	**76,635**	**76,635**	**78,671**	**13.8%**	**13.8%**	**16.8%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,007**	**21,007**	**31,966**	**31,966**	**31,966**	**52.2%**	**52.2%**	**52.2%**	**9.7%**
WESTERN INTERCONNECTION	**154,903**	**149,523**	**239,564**	**239,564**	**241,178**	**54.7%**	**54.7%**	**55.7%**	**14.2%**

Table 12: Demand, Resources, and Reserve Margins - Winter 2013/2014

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	53,472	51,900	80,107	80,107	82,313	49.8%	49.8%	53.9%	13.75%
FRCC	48,889	45,350	61,569	61,918	61,918	25.9%	26.7%	26.7%	15.0%
MISO	77,410	69,591	109,615	126,757	126,757	41.6%	63.7%	63.7%	15.0%
MRO-MAPP	5,316	4,929	7,734	7,734	7,734	45.5%	45.5%	45.5%	15.0%
NPCC-New England (ISO-NE)	22,510	19,661	33,553	39,799	40,163	49.1%	76.8%	78.4%	15.0%
NPCC-New York (NYISO)	24,761	24,761	46,451	46,451	46,666	87.6%	87.6%	88.5%	15.5%
PJM	135,529	127,243	199,712	199,712	199,712	47.4%	47.4%	47.4%	15.0%
SERC-E	43,227	41,759	58,607	58,607	58,607	35.6%	35.6%	35.6%	15.0%
SERC-N	47,509	45,703	62,105	62,696	62,696	30.7%	32.0%	32.0%	15.0%
SERC-SE	46,275	44,349	66,063	69,136	69,136	42.8%	49.4%	49.4%	15.0%
SERC-W	20,967	20,110	35,274	41,744	41,744	68.2%	99.1%	99.1%	15.0%
SPP	42,173	41,165	67,145	71,798	71,843	59.2%	70.2%	70.4%	13.6%
WECC-BASN	12,022	11,730	15,851	15,851	15,937	31.9%	31.9%	32.6%	12.6%
WECC-CALN	18,356	18,109	31,208	31,208	31,221	70.0%	70.0%	70.1%	14.2%
WECC-CALS	23,206	21,632	49,638	49,638	49,838	113.9%	113.9%	114.8%	14.9%
WECC-DSW	17,858	17,592	34,175	34,175	35,174	91.4%	91.4%	97.0%	13.5%
WECC-NORW	30,098	30,038	36,559	36,559	36,560	21.5%	21.5%	21.5%	17.2%
WECC-ROCK	9,923	9,673	16,444	16,444	16,464	65.7%	65.7%	65.9%	12.5%
TOTAL-UNITED STATES	**679,500**	**645,294**	**1,011,811**	**1,050,335**	**1,054,483**	**48.9%**	**54.6%**	**55.2%**	**15.0%**
MRO-Manitoba Hydro	4,630	4,404	5,864	5,864	5,864	26.7%	26.7%	26.7%	12.0%
MRO-SaskPower	3,676	3,585	4,172	4,172	4,172	13.5%	13.5%	13.5%	13.0%
NPCC-Maritimes	5,591	5,225	7,226	7,226	7,226	29.2%	29.2%	29.2%	20.0%
NPCC-Ontario (IESO)	22,085	20,576	31,854	31,854	31,907	44.2%	44.2%	44.5%	18.7%
NPCC-Québec	38,341	36,741	43,139	43,139	43,139	12.5%	12.5%	12.5%	11.6%
WECC-AESO	11,336	11,273	15,010	15,010	15,325	32.4%	32.4%	35.2%	12.3%
WECC-BC	11,142	11,079	13,423	13,423	13,516	20.5%	20.5%	21.3%	12.3%
TOTAL-CANADA	**96,801**	**92,883**	**120,688**	**120,688**	**121,150**	**24.7%**	**24.7%**	**25.2%**	**10.0%**
TOTAL-MÉXICO	**1,593**	**1,593**	**2,990**	**2,990**	**3,065**	**87.7%**	**87.7%**	**92.4%**	**11.9%**
TOTAL-NERC	**777,894**	**739,770**	**1,135,489**	**1,174,013**	**1,178,698**	**46.0%**	**50.9%**	**51.5%**	**15.0%**
EASTERN INTERCONNECTION	**550,548**	**518,411**	**796,945**	**835,469**	**836,146**	**44.8%**	**51.8%**	**51.9%**	**15.0%**
ERCOT INTERCONNECTION	**53,472**	**51,900**	**80,107**	**80,107**	**82,313**	**49.8%**	**49.8%**	**53.9%**	**13.75%**
QUÉBEC INTERCONNECTION	**38,341**	**36,741**	**43,139**	**43,139**	**43,139**	**12.5%**	**12.5%**	**12.5%**	**9.7%**
WESTERN INTERCONNECTION	**134,276**	**131,524**	**230,390**	**230,390**	**232,212**	**71.6%**	**71.6%**	**72.9%**	**15.0%**

Table 13: Demand, Resources, and Reserve Margins - Summer 2014

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	70,004	68,381	78,846	78,846	81,320	12.6%	12.6%	16.2%	13.75%
FRCC	48,228	44,787	59,683	60,211	60,211	23.8%	24.8%	24.8%	15.0%
MISO	95,227	87,408	114,528	131,670	131,670	20.3%	38.3%	38.3%	15.0%
MRO-MAPP	5,401	5,285	7,013	7,013	7,013	29.8%	29.8%	29.8%	15.0%
NPCC-New England (ISO-NE)	28,970	25,571	34,395	37,404	38,298	18.7%	29.1%	32.2%	15.0%
NPCC-New York (NYISO)	33,609	31,556	45,817	45,817	46,041	36.3%	36.3%	37.0%	15.5%
PJM	164,772	155,793	200,404	200,404	204,545	21.6%	21.6%	24.1%	15.0%
SERC-E	45,521	43,450	56,329	56,329	56,329	23.7%	23.7%	23.7%	15.0%
SERC-N	48,050	45,224	60,528	61,056	61,056	26.0%	27.1%	27.1%	15.0%
SERC-SE	52,596	50,577	64,377	67,500	67,500	22.4%	28.3%	28.3%	15.0%
SERC-W	26,470	25,554	34,307	40,933	40,933	29.6%	54.6%	54.6%	15.0%
SPP	55,485	54,140	69,713	74,132	74,369	25.6%	33.6%	34.0%	13.6%
WECC-BASN	15,416	14,331	18,808	18,808	19,524	22.0%	22.0%	26.7%	12.6%
WECC-CALN	25,965	25,045	37,447	37,447	37,479	44.2%	44.2%	44.3%	14.2%
WECC-CALS	34,279	31,940	56,031	56,031	56,248	63.5%	63.5%	64.1%	14.9%
WECC-DSW	29,611	29,091	36,511	36,511	38,345	23.3%	23.3%	29.5%	13.5%
WECC-NORW	25,410	25,365	34,785	34,785	34,790	36.9%	36.9%	36.9%	17.2%
WECC-ROCK	11,697	11,269	16,813	16,813	17,144	43.7%	43.7%	46.6%	12.5%
TOTAL-UNITED STATES	**816,711**	**774,767**	**1,026,337**	**1,061,712**	**1,072,816**	**25.7%**	**30.0%**	**31.4%**	**15.0%**
MRO-Manitoba Hydro	3,282	3,055	4,832	4,832	4,832	47.2%	47.2%	47.2%	12.0%
MRO-SaskPower	3,388	3,297	3,802	3,802	3,802	12.2%	12.2%	12.2%	13.0%
NPCC-Maritimes	3,705	3,335	6,957	6,957	6,957	87.8%	87.8%	87.8%	20.0%
NPCC-Ontario (IESO)	22,803	21,219	29,289	29,289	29,342	28.4%	28.4%	28.7%	18.7%
NPCC-Québec	20,961	20,961	32,284	32,284	32,284	54.0%	54.0%	54.0%	11.6%
WECC-AESO	11,581	11,528	14,038	14,038	14,353	21.2%	21.2%	23.9%	12.3%
WECC-BC	8,454	8,401	10,030	10,030	10,850	18.6%	18.6%	28.3%	12.3%
TOTAL-CANADA	**74,174**	**71,796**	**101,232**	**101,232**	**102,420**	**36.5%**	**36.5%**	**38.1%**	**10.0%**
TOTAL-MÉXICO	**2,511**	**2,511**	**3,670**	**3,670**	**3,700**	**46.2%**	**46.2%**	**47.4%**	**11.9%**
TOTAL-NERC	**893,396**	**849,073**	**1,131,239**	**1,166,614**	**1,178,936**	**26.6%**	**30.6%**	**32.0%**	**15.0%**
EASTERN INTERCONNECTION	**637,508**	**600,251**	**791,976**	**827,351**	**832,899**	**24.2%**	**29.8%**	**30.6%**	**15.0%**
ERCOT INTERCONNECTION	**70,004**	**68,381**	**78,846**	**78,846**	**81,320**	**12.6%**	**12.6%**	**16.2%**	**13.75%**
QUÉBEC INTERCONNECTION	**20,961**	**20,961**	**32,284**	**32,284**	**32,284**	**54.0%**	**54.0%**	**54.0%**	**9.7%**
WESTERN INTERCONNECTION	**157,599**	**152,209**	**252,019**	**252,019**	**255,118**	**59.9%**	**59.9%**	**61.9%**	**14.2%**

Table 14: Demand, Resources, and Reserve Margins - Winter 2014/2015

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	55,126	53,503	82,318	82,318	85,056	49.3%	49.3%	54.3%	13.75%
FRCC	49,534	45,923	64,856	65,384	65,384	30.9%	32.0%	32.0%	15.0%
MISO	77,725	69,906	109,634	126,776	126,776	41.1%	63.1%	63.1%	15.0%
MRO-MAPP	5,368	4,977	7,739	7,739	7,739	44.2%	44.2%	44.2%	15.0%
NPCC-New England (ISO-NE)	22,630	19,406	34,619	39,386	40,280	53.0%	74.0%	78.0%	15.0%
NPCC-New York (NYISO)	24,810	24,810	46,456	46,456	46,725	87.2%	87.2%	88.3%	15.5%
PJM	136,948	128,662	200,302	200,302	200,302	46.3%	46.3%	46.3%	15.0%
SERC-E	43,699	42,217	57,848	57,848	57,848	32.4%	32.4%	32.4%	15.0%
SERC-N	46,612	44,357	60,392	60,983	60,983	29.6%	30.8%	30.8%	15.0%
SERC-SE	47,038	45,014	66,391	69,622	69,622	41.1%	48.0%	48.0%	15.0%
SERC-W	21,417	20,656	34,895	41,698	41,698	62.9%	94.7%	94.7%	15.0%
SPP	42,092	41,073	67,597	72,249	72,620	60.6%	71.6%	72.5%	13.6%
WECC-BASN	12,292	11,990	16,082	16,082	16,798	30.8%	30.8%	36.7%	12.6%
WECC-CALN	18,607	18,352	31,688	31,688	31,701	70.3%	70.3%	70.4%	14.2%
WECC-CALS	23,683	22,104	50,071	50,071	50,288	111.4%	111.4%	112.3%	14.9%
WECC-DSW	18,246	18,010	33,270	33,270	34,662	82.3%	82.3%	90.0%	13.5%
WECC-NORW	30,355	30,290	36,997	36,997	36,998	21.9%	21.9%	21.9%	17.2%
WECC-ROCK	10,091	9,839	16,852	16,852	17,093	67.0%	67.0%	69.4%	12.5%
TOTAL-UNITED STATES	**686,273**	**651,088**	**1,018,007**	**1,055,722**	**1,062,573**	**48.3%**	**53.8%**	**54.8%**	**15.0%**
MRO-Manitoba Hydro	4,670	4,444	5,850	5,850	5,850	25.3%	25.3%	25.3%	12.0%
MRO-SaskPower	3,805	3,714	4,174	4,174	4,174	9.7%	9.7%	9.7%	13.0%
NPCC-Maritimes	5,602	5,242	7,227	7,227	7,227	29.0%	29.0%	29.0%	20.0%
NPCC-Ontario (IESO)	21,928	20,315	29,968	29,968	30,055	36.7%	36.7%	37.1%	18.7%
NPCC-Québec	38,797	37,447	44,377	44,377	44,377	14.4%	14.4%	14.4%	11.6%
WECC-AESO	12,099	12,036	15,416	15,416	15,731	27.4%	27.4%	30.0%	12.3%
WECC-BC	11,138	11,075	13,041	13,041	13,194	17.1%	17.1%	18.5%	12.3%
TOTAL-CANADA	**98,039**	**94,272**	**120,053**	**120,053**	**120,607**	**22.5%**	**22.5%**	**23.0%**	**10.0%**
TOTAL-MÉXICO	**1,672**	**1,672**	**3,184**	**3,184**	**3,180**	**90.4%**	**90.4%**	**90.2%**	**11.9%**
TOTAL-NERC	**785,984**	**747,032**	**1,141,244**	**1,178,959**	**1,186,360**	**45.2%**	**50.0%**	**50.9%**	**15.0%**
EASTERN INTERCONNECTION	**553,878**	**520,714**	**797,948**	**835,663**	**837,282**	**44.1%**	**50.9%**	**51.2%**	**15.0%**
ERCOT INTERCONNECTION	**55,126**	**53,503**	**82,318**	**82,318**	**85,056**	**49.3%**	**49.3%**	**54.3%**	**13.75%**
QUÉBEC INTERCONNECTION	**38,797**	**37,447**	**44,377**	**44,377**	**44,377**	**14.4%**	**14.4%**	**14.4%**	**9.7%**
WESTERN INTERCONNECTION	**137,184**	**134,432**	**242,909**	**242,909**	**245,723**	**77.1%**	**77.1%**	**79.1%**	**15.0%**

Table 15: Demand, Resources, and Reserve Margins - Summer 2015

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	71,910	70,231	79,682	79,682	82,575	10.8%	10.8%	14.8%	13.75%
FRCC	49,278	45,770	60,761	61,288	61,288	23.3%	24.4%	24.4%	15.0%
MISO	95,947	88,128	114,551	131,693	131,693	19.4%	37.3%	37.3%	15.0%
MRO-MAPP	5,497	5,379	7,065	7,065	7,065	28.5%	28.5%	28.5%	15.0%
NPCC-New England (ISO-NE)	29,380	25,981	32,886	35,895	36,936	11.9%	22.2%	25.7%	15.0%
NPCC-New York (NYISO)	33,678	31,625	46,819	46,819	47,052	39.0%	39.0%	39.7%	15.5%
PJM	166,506	157,527	200,990	200,990	206,142	20.7%	20.7%	23.8%	15.0%
SERC-E	46,067	43,952	55,023	55,023	55,023	19.4%	19.4%	19.4%	15.0%
SERC-N	48,437	45,471	58,570	59,133	59,133	20.9%	22.1%	22.1%	15.0%
SERC-SE	53,378	51,185	64,256	67,342	67,342	20.4%	26.2%	26.2%	15.0%
SERC-W	26,806	25,859	33,814	41,110	41,110	26.1%	53.4%	53.4%	15.0%
SPP	55,556	54,263	69,176	73,595	73,834	24.5%	32.5%	32.9%	13.6%
WECC-BASN	15,682	14,588	19,325	19,325	20,041	23.2%	23.2%	27.8%	12.6%
WECC-CALN	26,381	25,452	38,142	38,142	38,174	44.6%	44.6%	44.7%	14.2%
WECC-CALS	34,859	32,513	56,895	56,895	57,152	63.2%	63.2%	64.0%	14.9%
WECC-DSW	30,208	29,681	37,042	37,042	39,607	22.6%	22.6%	31.1%	13.5%
WECC-NORW	25,636	25,591	34,978	34,978	35,030	36.4%	36.4%	36.6%	17.2%
WECC-ROCK	11,983	11,566	17,203	17,203	17,321	43.6%	43.6%	44.5%	12.5%
TOTAL-UNITED STATES	**827,189**	**784,762**	**1,027,178**	**1,063,221**	**1,076,518**	**24.2%**	**28.5%**	**30.1%**	**15.0%**
MRO-Manitoba Hydro	3,288	3,061	5,170	5,170	5,170	57.2%	57.2%	57.2%	12.0%
MRO-SaskPower	3,507	3,416	3,885	3,885	3,885	10.8%	10.8%	10.8%	13.0%
NPCC-Maritimes	3,706	3,341	6,988	6,988	6,988	88.6%	88.6%	88.6%	20.0%
NPCC-Ontario (IESO)	22,349	20,763	29,026	29,026	29,170	29.9%	29.9%	30.5%	19.8%
NPCC-Québec	21,169	21,169	32,724	32,724	32,724	54.6%	54.6%	54.6%	11.6%
WECC-AESO	12,111	12,058	14,266	14,266	14,620	17.8%	17.8%	20.7%	12.3%
WECC-BC	8,612	8,559	10,192	10,192	11,019	18.3%	18.3%	27.9%	12.3%
TOTAL-CANADA	**74,742**	**72,367**	**102,250**	**102,250**	**103,575**	**36.8%**	**36.8%**	**38.6%**	**10.0%**
TOTAL-MÉXICO	**2,626**	**2,626**	**3,679**	**3,679**	**3,709**	**40.1%**	**40.1%**	**41.2%**	**11.9%**
TOTAL-NERC	**904,557**	**859,755**	**1,133,108**	**1,169,151**	**1,183,802**	**25.3%**	**29.3%**	**30.9%**	**15.0%**
EASTERN INTERCONNECTION	**643,380**	**605,721**	**788,980**	**825,023**	**831,831**	**22.6%**	**28.2%**	**29.3%**	**15.0%**
ERCOT INTERCONNECTION	**71,910**	**70,231**	**79,682**	**79,682**	**82,575**	**10.8%**	**10.8%**	**14.8%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,169**	**21,169**	**32,724**	**32,724**	**32,724**	**54.6%**	**54.6%**	**54.6%**	**9.7%**
WESTERN INTERCONNECTION	**160,812**	**155,401**	**257,189**	**257,189**	**260,799**	**59.9%**	**59.9%**	**62.2%**	**14.2%**

Table 16: Demand, Resources, and Reserve Margins - Winter 2015/2016

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	56,398	54,719	83,774	83,774	86,667	48.5%	48.5%	53.7%	13.75%
FRCC	50,148	46,503	64,188	64,716	64,716	28.0%	29.0%	29.0%	15.0%
MISO	78,574	70,755	109,657	126,799	126,799	39.6%	61.4%	61.4%	15.0%
MRO-MAPP	5,459	5,062	7,714	7,714	7,714	41.3%	41.3%	41.3%	15.0%
NPCC-New England (ISO-NE)	22,750	19,526	33,360	38,128	39,169	46.6%	67.6%	72.2%	15.0%
NPCC-New York (NYISO)	24,828	24,828	47,571	47,571	47,866	91.6%	91.6%	92.8%	15.5%
PJM	137,985	129,699	200,308	200,308	200,308	45.2%	45.2%	45.2%	15.0%
SERC-E	44,242	42,753	57,119	57,119	57,119	29.1%	29.1%	29.1%	15.0%
SERC-N	47,024	44,660	59,478	60,448	60,448	26.5%	28.5%	28.5%	15.0%
SERC-SE	47,721	45,521	67,022	70,253	70,253	40.4%	47.2%	47.2%	15.0%
SERC-W	21,734	20,945	34,399	41,884	41,884	58.3%	92.7%	92.7%	15.0%
SPP	42,660	41,691	67,314	71,966	72,339	57.8%	68.7%	69.6%	13.6%
WECC-BASN	12,522	12,217	16,053	16,053	16,832	28.2%	28.2%	34.4%	12.6%
WECC-CALN	18,913	18,651	34,674	34,674	34,687	83.3%	83.3%	83.4%	14.2%
WECC-CALS	24,092	22,509	50,678	50,678	50,935	110.4%	110.4%	111.4%	14.9%
WECC-DSW	18,598	18,356	31,620	31,620	33,892	70.0%	70.0%	82.2%	13.5%
WECC-NORW	30,610	30,545	37,237	37,237	37,424	21.7%	21.7%	22.3%	17.2%
WECC-ROCK	10,332	10,079	17,195	17,195	17,331	66.4%	66.4%	67.7%	12.5%
TOTAL-UNITED STATES	**694,589**	**659,017**	**1,019,361**	**1,058,137**	**1,066,384**	**46.8%**	**52.3%**	**53.5%**	**15.0%**
MRO-Manitoba Hydro	4,703	4,477	5,939	5,939	5,939	26.3%	26.3%	26.3%	12.0%
MRO-SaskPower	3,924	3,833	4,443	4,443	4,443	13.2%	13.2%	13.2%	13.0%
NPCC-Maritimes	5,612	5,258	7,264	7,264	7,264	29.4%	29.4%	29.4%	20.0%
NPCC-Ontario (IESO)	21,772	20,156	30,678	30,678	30,974	40.9%	40.9%	42.3%	19.8%
NPCC-Québec	39,193	37,843	44,935	44,935	44,935	14.7%	14.7%	14.7%	11.6%
WECC-AESO	12,517	12,454	16,088	16,088	16,442	28.5%	28.5%	31.4%	12.3%
WECC-BC	11,006	10,943	13,134	13,134	13,404	19.3%	19.3%	21.8%	12.3%
TOTAL-CANADA	**98,727**	**94,964**	**122,482**	**122,482**	**123,401**	**24.1%**	**24.1%**	**25.0%**	**10.0%**
TOTAL-MÉXICO	**1,749**	**1,749**	**3,104**	**3,104**	**3,128**	**77.5%**	**77.5%**	**78.8%**	**11.9%**
TOTAL-NERC	**795,065**	**755,731**	**1,144,947**	**1,183,723**	**1,192,913**	**44.0%**	**48.9%**	**50.0%**	**15.0%**
EASTERN INTERCONNECTION	**559,136**	**525,667**	**796,454**	**835,230**	**837,235**	**42.4%**	**49.4%**	**49.7%**	**15.0%**
ERCOT INTERCONNECTION	**56,398**	**54,719**	**83,774**	**83,774**	**86,667**	**48.5%**	**48.5%**	**53.7%**	**13.75%**
QUÉBEC INTERCONNECTION	**39,193**	**37,843**	**44,935**	**44,935**	**44,935**	**14.7%**	**14.7%**	**14.7%**	**9.7%**
WESTERN INTERCONNECTION	**139,765**	**136,992**	**251,293**	**251,293**	**255,271**	**79.8%**	**79.8%**	**82.6%**	**15.0%**

Table 17: Demand, Resources, and Reserve Margins - Summer 2016

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	73,369	71,628	81,024	81,024	84,528	10.4%	10.4%	15.2%	13.75%
FRCC	50,036	46,496	60,844	61,395	61,395	21.6%	22.7%	22.7%	15.0%
MISO	96,637	88,818	114,633	131,775	131,775	18.6%	36.4%	36.4%	15.0%
MRO-MAPP	5,657	5,537	7,207	7,207	7,207	27.4%	27.4%	27.4%	15.0%
NPCC-New England (ISO-NE)	29,775	26,376	32,664	35,673	36,958	9.7%	19.8%	24.1%	15.0%
NPCC-New York (NYISO)	33,749	31,696	46,819	46,819	47,067	38.7%	38.7%	39.5%	15.5%
PJM	167,847	158,868	200,990	200,990	206,297	19.7%	19.7%	22.9%	15.0%
SERC-E	46,619	44,466	55,996	55,996	55,996	20.1%	20.1%	20.1%	15.0%
SERC-N	49,125	45,999	57,937	58,879	58,879	17.9%	19.9%	19.9%	15.0%
SERC-SE	54,215	51,926	66,690	69,776	69,776	23.0%	28.7%	28.7%	15.0%
SERC-W	27,137	26,187	32,877	40,264	40,264	21.2%	48.4%	48.4%	15.0%
SPP	56,194	54,879	69,840	74,259	74,691	24.3%	32.1%	32.9%	13.6%
WECC-BASN	15,829	14,705	18,944	18,944	19,993	19.7%	19.7%	26.3%	12.6%
WECC-CALN	27,053	26,114	39,792	39,792	39,825	47.1%	47.1%	47.2%	14.2%
WECC-CALS	35,426	33,076	56,911	56,911	57,288	60.6%	60.6%	61.7%	14.9%
WECC-DSW	30,840	30,313	39,678	39,678	43,321	28.7%	28.7%	40.5%	13.5%
WECC-NORW	25,890	25,845	34,962	34,962	35,103	35.0%	35.0%	35.6%	17.2%
WECC-ROCK	12,236	11,828	16,943	16,943	17,303	38.5%	38.5%	41.4%	12.5%
TOTAL-UNITED STATES	**837,634**	**794,756**	**1,034,752**	**1,071,288**	**1,087,666**	**23.5%**	**27.9%**	**29.8%**	**15.0%**
MRO-Manitoba Hydro	3,325	3,098	5,170	5,170	5,170	55.5%	55.5%	55.5%	12.0%
MRO-SaskPower	3,596	3,505	4,061	4,061	4,061	12.9%	12.9%	12.9%	13.0%
NPCC-Maritimes	3,686	3,326	6,986	6,986	6,986	89.5%	89.5%	89.5%	20.0%
NPCC-Ontario (IESO)	22,045	20,456	27,626	27,626	28,510	25.3%	25.3%	29.3%	20.0%
NPCC-Québec	21,283	21,283	32,968	32,968	32,968	54.9%	54.9%	54.9%	11.6%
WECC-AESO	12,552	12,499	14,759	14,759	15,113	17.6%	17.6%	20.4%	12.3%
WECC-BC	8,655	8,602	10,402	10,402	11,158	20.2%	20.2%	28.9%	12.3%
TOTAL-CANADA	**75,143**	**72,770**	**101,971**	**101,971**	**103,964**	**35.7%**	**35.7%**	**38.4%**	**10.0%**
TOTAL-MÉXICO	**2,747**	**2,747**	**3,925**	**3,925**	**4,230**	**42.9%**	**42.9%**	**54.0%**	**11.9%**
TOTAL-NERC	**915,523**	**870,273**	**1,140,648**	**1,177,184**	**1,195,861**	**24.6%**	**28.6%**	**30.6%**	**15.0%**
EASTERN INTERCONNECTION	**649,643**	**611,633**	**790,340**	**826,876**	**835,031**	**21.7%**	**27.3%**	**28.5%**	**15.0%**
ERCOT INTERCONNECTION	**73,369**	**71,628**	**81,024**	**81,024**	**84,528**	**10.4%**	**10.4%**	**15.2%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,283**	**21,283**	**32,968**	**32,968**	**32,968**	**54.9%**	**54.9%**	**54.9%**	**9.7%**
WESTERN INTERCONNECTION	**163,594**	**158,148**	**265,269**	**265,269**	**271,242**	**62.2%**	**62.2%**	**65.8%**	**14.2%**

Table 18: Demand, Resources, and Reserve Margins - Winter 2016/2017

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Anticipated (MW)	Prospective (MW)	Adjusted Potential (MW)	Anticipated (%)	Prospective (%)	Adjusted Potential (%)	NERC Reference Margin Level (%)
ERCOT	58,733	56,992	85,116	85,116	88,620	44.9%	44.9%	50.9%	13.75%
FRCC	50,812	47,109	65,370	65,921	65,921	28.7%	29.7%	29.7%	15.0%
MISO	79,267	71,448	109,739	126,881	126,881	38.4%	60.1%	60.1%	15.0%
MRO-MAPP	5,552	5,150	7,784	7,784	7,784	40.2%	40.2%	40.2%	15.0%
NPCC-New England (ISO-NE)	22,875	19,651	33,335	38,103	39,388	45.7%	66.6%	72.2%	15.0%
NPCC-New York (NYISO)	24,908	24,908	47,571	47,571	47,910	91.0%	91.0%	92.3%	15.5%
PJM	139,073	130,787	200,308	200,308	200,308	44.0%	44.0%	44.0%	15.0%
SERC-E	44,739	43,242	58,247	58,247	58,247	30.2%	30.2%	30.2%	15.0%
SERC-N	47,124	44,652	59,586	60,598	60,598	26.4%	28.6%	28.6%	15.0%
SERC-SE	48,432	46,135	68,526	71,757	71,757	41.5%	48.2%	48.2%	15.0%
SERC-W	22,070	21,267	33,452	41,028	41,028	51.6%	85.9%	85.9%	15.0%
SPP	43,178	42,193	68,008	72,660	73,347	57.5%	68.3%	69.9%	13.6%
WECC-BASN	12,720	12,415	16,554	16,554	17,636	30.1%	30.1%	38.7%	12.6%
WECC-CALN	19,260	18,991	35,968	35,968	35,981	86.8%	86.8%	86.8%	14.2%
WECC-CALS	24,457	22,871	51,404	51,404	51,781	110.2%	110.2%	111.7%	14.9%
WECC-DSW	19,069	18,827	33,414	33,414	36,563	75.2%	75.2%	91.7%	13.5%
WECC-NORW	30,881	30,816	37,583	37,583	37,638	21.7%	21.7%	21.9%	17.2%
WECC-ROCK	10,633	10,421	17,249	17,249	17,271	62.2%	62.2%	62.4%	12.5%
TOTAL-UNITED STATES	**703,782**	**667,874**	**1,029,215**	**1,068,147**	**1,078,660**	**46.2%**	**51.8%**	**53.3%**	**15.0%**
MRO-Manitoba Hydro	4,752	4,526	5,939	5,939	5,939	25.0%	25.0%	25.0%	12.0%
MRO-SaskPower	4,023	3,932	4,469	4,469	4,469	11.1%	11.1%	11.1%	13.0%
NPCC-Maritimes	5,589	5,241	7,264	7,264	7,264	30.0%	30.0%	30.0%	20.0%
NPCC-Ontario (IESO)	21,658	20,040	28,083	28,083	29,171	29.7%	29.7%	34.7%	20.0%
NPCC-Québec	39,500	38,150	45,401	45,401	45,401	14.9%	14.9%	14.9%	11.6%
WECC-AESO	12,983	12,920	16,123	16,123	16,477	24.2%	24.2%	26.9%	12.3%
WECC-BC	11,917	11,854	14,097	14,097	14,307	18.3%	18.3%	20.1%	12.3%
TOTAL-CANADA	**100,422**	**96,663**	**121,377**	**121,377**	**123,028**	**20.9%**	**20.9%**	**22.5%**	**10.0%**
TOTAL-MÉXICO	**1,829**	**1,829**	**3,323**	**3,323**	**3,353**	**81.7%**	**81.7%**	**83.3%**	**11.9%**
TOTAL-NERC	**806,033**	**766,365**	**1,153,914**	**1,192,846**	**1,205,041**	**43.2%**	**48.0%**	**49.5%**	**15.0%**
EASTERN INTERCONNECTION	**564,052**	**530,280**	**797,682**	**836,614**	**840,012**	**41.4%**	**48.3%**	**48.9%**	**15.0%**
ERCOT INTERCONNECTION	**58,733**	**56,992**	**85,116**	**85,116**	**88,620**	**44.9%**	**44.9%**	**50.9%**	**13.75%**
QUÉBEC INTERCONNECTION	**39,500**	**38,150**	**45,401**	**45,401**	**45,401**	**14.9%**	**14.9%**	**14.9%**	**9.7%**
WESTERN INTERCONNECTION	**141,714**	**138,972**	**250,862**	**250,862**	**255,975**	**77.0%**	**77.0%**	**80.6%**	**15.0%**

Table 19: Demand, Resources, and Reserve Margins - Summer 2017

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	74,385	72,577	81,711	81,711	85,369	9.8%	9.8%	14.8%	13.75%
FRCC	50,833	47,227	61,177	61,728	61,728	20.3%	21.4%	21.4%	15.0%
MISO	97,332	89,513	114,633	131,775	131,775	17.8%	35.4%	35.4%	15.0%
MRO-MAPP	5,688	5,566	7,209	7,209	7,209	26.7%	26.7%	26.7%	15.0%
NPCC-New England (ISO-NE)	30,155	26,756	32,639	35,648	36,933	8.2%	18.2%	22.5%	15.0%
NPCC-New York (NYISO)	33,916	31,863	46,819	46,819	47,073	38.0%	38.0%	38.8%	15.5%
PJM	169,443	160,464	200,990	200,990	206,522	18.6%	18.6%	21.9%	15.0%
SERC-E	47,050	44,867	56,073	56,073	56,073	19.2%	19.2%	19.2%	15.0%
SERC-N	49,615	46,339	58,087	59,029	59,029	17.1%	19.0%	19.0%	15.0%
SERC-SE	54,974	52,674	67,576	70,662	70,662	22.9%	28.5%	28.5%	15.0%
SERC-W	27,467	26,513	32,063	40,268	40,268	16.7%	46.6%	46.6%	15.0%
SPP	57,075	55,485	71,295	75,714	76,668	24.9%	32.7%	34.3%	13.6%
WECC-BASN	16,075	14,951	19,020	19,020	20,069	18.3%	18.3%	24.8%	12.6%
WECC-CALN	27,493	26,544	39,795	39,795	39,948	44.7%	44.7%	45.3%	14.2%
WECC-CALS	35,986	33,632	56,021	56,021	56,422	55.7%	55.7%	56.8%	14.9%
WECC-DSW	31,577	31,050	39,567	39,567	43,699	25.3%	25.3%	38.4%	13.5%
WECC-NORW	26,139	26,094	34,923	34,923	35,103	33.6%	33.6%	34.3%	17.2%
WECC-ROCK	12,563	12,211	16,883	16,883	17,222	34.4%	34.4%	37.1%	12.5%
TOTAL-UNITED STATES	**847,766**	**804,327**	**1,036,481**	**1,073,836**	**1,091,772**	**22.3%**	**26.7%**	**28.8%**	**15.0%**
MRO-Manitoba Hydro	3,265	3,038	5,170	5,170	5,170	58.3%	58.3%	58.3%	12.0%
MRO-SaskPower	3,631	3,540	4,103	4,103	4,103	13.0%	13.0%	13.0%	13.0%
NPCC-Maritimes	3,685	3,331	6,983	6,983	6,983	89.5%	89.5%	89.5%	20.0%
NPCC-Ontario (IESO)	21,944	20,352	26,688	26,688	27,975	21.6%	21.6%	27.5%	20.0%
NPCC-Québec	21,371	21,371	33,816	33,816	33,816	58.2%	58.2%	58.2%	11.6%
WECC-AESO	13,178	13,125	14,775	14,775	15,129	12.1%	12.1%	14.8%	12.3%
WECC-BC	8,701	8,648	10,444	10,444	11,249	20.0%	20.0%	29.3%	12.3%
TOTAL-CANADA	**75,775**	**73,405**	**101,978**	**101,978**	**104,424**	**34.6%**	**34.6%**	**37.8%**	**10.0%**
TOTAL-MÉXICO	**2,873**	**2,873**	**3,842**	**3,842**	**4,147**	**33.7%**	**33.7%**	**44.3%**	**11.9%**
TOTAL-NERC	**926,414**	**880,605**	**1,142,302**	**1,179,656**	**1,200,344**	**23.3%**	**27.3%**	**29.6%**	**15.0%**
EASTERN INTERCONNECTION	**656,073**	**617,529**	**791,505**	**828,859**	**838,171**	**20.6%**	**26.3%**	**27.8%**	**15.0%**
ERCOT INTERCONNECTION	**74,385**	**72,577**	**81,711**	**81,711**	**85,369**	**9.8%**	**9.8%**	**14.8%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,371**	**21,371**	**33,816**	**33,816**	**33,816**	**58.2%**	**58.2%**	**58.2%**	**9.7%**
WESTERN INTERCONNECTION	**166,437**	**161,033**	**265,404**	**265,404**	**272,100**	**59.5%**	**59.5%**	**63.5%**	**14.2%**

Table 20: Demand, Resources, and Reserve Margins - Winter 2017/2018

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Anticipated (MW)	Prospective (MW)	Adjusted Potential (MW)	Anticipated (%)	Prospective (%)	Adjusted Potential (%)	NERC Reference Margin Level (%)
ERCOT	59,330	57,522	85,183	85,183	88,841	43.6%	43.6%	49.7%	13.75%
FRCC	51,408	47,644	65,690	66,241	66,241	27.8%	28.9%	28.9%	15.0%
MISO	79,992	72,173	109,739	126,881	126,881	37.2%	58.6%	58.6%	15.0%
MRO-MAPP	5,636	5,229	7,788	7,788	7,788	38.2%	38.2%	38.2%	15.0%
NPCC-New England (ISO-NE)	23,000	19,776	33,335	38,103	39,388	44.9%	65.7%	71.3%	15.0%
NPCC-New York (NYISO)	25,014	25,014	47,571	47,571	47,928	90.2%	90.2%	91.6%	15.5%
PJM	140,040	131,754	200,308	200,308	200,308	43.0%	43.0%	43.0%	15.0%
SERC-E	45,231	43,725	58,268	58,268	58,268	28.8%	28.8%	28.8%	15.0%
SERC-N	47,284	44,814	58,342	59,354	59,354	23.4%	25.5%	25.5%	15.0%
SERC-SE	49,001	46,692	69,956	73,187	73,187	42.8%	49.4%	49.4%	15.0%
SERC-W	22,394	21,587	32,631	41,032	41,032	45.7%	83.2%	83.2%	15.0%
SPP	43,805	42,669	69,052	73,704	75,154	57.6%	68.3%	71.6%	13.6%
WECC-BASN	12,925	12,620	16,494	16,494	17,576	27.6%	27.6%	36.0%	12.6%
WECC-CALN	19,584	19,308	36,063	36,063	36,176	84.1%	84.1%	84.7%	14.2%
WECC-CALS	24,879	23,289	51,735	51,735	52,136	107.9%	107.9%	109.6%	14.9%
WECC-DSW	19,510	19,268	32,464	32,464	35,868	66.4%	66.4%	83.8%	13.5%
WECC-NORW	31,166	31,101	38,234	38,234	38,292	22.7%	22.7%	22.9%	17.2%
WECC-ROCK	10,908	10,695	17,202	17,202	17,225	57.7%	57.7%	57.9%	12.5%
TOTAL-UNITED STATES	**711,108**	**674,880**	**1,030,057**	**1,069,814**	**1,081,645**	**44.9%**	**50.4%**	**52.1%**	**15.0%**
MRO-Manitoba Hydro	4,705	4,479	5,939	5,939	5,939	26.2%	26.2%	26.2%	12.0%
MRO-SaskPower	4,062	3,971	4,469	4,469	4,469	10.0%	10.0%	10.0%	13.0%
NPCC-Maritimes	5,586	5,243	7,264	7,264	7,264	30.0%	30.0%	30.0%	20.0%
NPCC-Ontario (IESO)	21,659	20,038	27,214	27,214	28,709	25.6%	25.6%	32.5%	20.0%
NPCC-Québec	39,786	38,516	46,235	46,235	46,235	16.2%	16.2%	16.2%	11.6%
WECC-AESO	13,485	13,422	16,102	16,102	16,456	19.4%	19.4%	22.0%	12.3%
WECC-BC	11,946	11,883	14,083	14,083	14,249	17.9%	17.9%	19.3%	12.3%
TOTAL-CANADA	**101,229**	**97,552**	**121,306**	**121,306**	**123,321**	**19.8%**	**19.8%**	**21.8%**	**10.0%**
TOTAL-MÉXICO	**1,913**	**1,913**	**3,416**	**3,416**	**3,721**	**78.6%**	**78.6%**	**94.5%**	**11.9%**
TOTAL-NERC	**814,249**	**774,345**	**1,154,779**	**1,194,536**	**1,208,687**	**41.8%**	**46.7%**	**48.4%**	**15.0%**
EASTERN INTERCONNECTION	**568,817**	**534,808**	**797,568**	**837,325**	**841,912**	**40.2%**	**47.2%**	**48.0%**	**15.0%**
ERCOT INTERCONNECTION	**59,330**	**57,522**	**85,183**	**85,183**	**88,841**	**43.6%**	**43.6%**	**49.7%**	**13.75%**
QUÉBEC INTERCONNECTION	**39,786**	**38,516**	**46,235**	**46,235**	**46,235**	**16.2%**	**16.2%**	**16.2%**	**9.7%**
WESTERN INTERCONNECTION	**144,197**	**141,443**	**249,316**	**249,316**	**255,032**	**72.9%**	**72.9%**	**76.9%**	**15.0%**

Table 21: Demand, Resources, and Reserve Margins - Summer 2018

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	75,521	73,638	81,786	81,786	85,444	8.3%	8.3%	13.1%	13.75%
FRCC	51,377	47,707	61,286	61,853	61,853	19.3%	20.4%	20.4%	15.0%
MISO	98,110	90,291	114,633	131,775	131,775	16.8%	34.3%	34.3%	15.0%
MRO-MAPP	5,776	5,652	7,211	7,211	7,211	24.8%	24.8%	24.8%	15.0%
NPCC-New England (ISO-NE)	30,525	27,126	32,639	35,648	36,933	6.9%	16.8%	21.0%	15.0%
NPCC-New York (NYISO)	34,190	32,137	46,819	46,819	47,073	36.9%	36.9%	37.7%	15.5%
PJM	171,067	162,088	200,990	200,990	206,392	17.5%	17.5%	20.6%	15.0%
SERC-E	47,636	45,432	56,104	56,104	56,104	17.8%	17.8%	17.8%	15.0%
SERC-N	50,162	46,757	57,010	57,952	57,952	13.7%	15.5%	15.5%	15.0%
SERC-SE	55,592	53,297	68,693	71,779	71,779	23.6%	29.1%	29.1%	15.0%
SERC-W	27,806	26,849	31,491	40,751	40,751	13.3%	46.6%	46.6%	15.0%
SPP	57,682	56,122	71,654	76,073	77,028	24.2%	31.9%	33.5%	13.6%
WECC-BASN	16,308	15,184	19,304	19,304	20,353	18.4%	18.4%	24.8%	12.6%
WECC-CALN	27,938	26,980	39,803	39,803	40,318	42.5%	42.5%	44.3%	14.2%
WECC-CALS	36,578	34,169	54,793	54,793	55,295	49.8%	49.8%	51.2%	14.9%
WECC-DSW	32,327	31,889	40,391	40,391	45,205	24.9%	24.9%	39.8%	13.5%
WECC-NORW	26,360	26,315	34,943	34,943	35,218	32.6%	32.6%	33.6%	17.2%
WECC-ROCK	12,828	12,483	16,888	16,888	17,227	31.6%	31.6%	34.3%	12.5%
TOTAL-UNITED STATES	**857,781**	**814,115**	**1,036,439**	**1,074,863**	**1,093,910**	**20.8%**	**25.3%**	**27.5%**	**15.0%**
MRO-Manitoba Hydro	3,295	3,068	5,170	5,170	5,170	56.9%	56.9%	56.9%	12.0%
MRO-SaskPower	3,666	3,575	4,353	4,353	4,353	18.7%	18.7%	18.7%	13.0%
NPCC-Maritimes	3,672	3,324	6,980	6,980	6,980	90.1%	90.1%	90.1%	20.0%
NPCC-Ontario (IESO)	21,981	20,387	25,215	25,215	27,499	14.7%	14.7%	25.1%	20.0%
NPCC-Québec	21,564	21,564	33,816	33,816	33,816	56.8%	56.8%	56.8%	11.6%
WECC-AESO	13,595	13,542	14,795	14,795	15,149	8.8%	8.8%	11.4%	12.3%
WECC-BC	8,694	8,641	10,403	10,403	11,204	19.7%	19.7%	28.9%	12.3%
TOTAL-CANADA	**76,467**	**74,101**	**100,730**	**100,730**	**104,170**	**31.7%**	**31.7%**	**36.2%**	**10.0%**
TOTAL-MÉXICO	**2,996**	**2,996**	**3,886**	**3,886**	**4,191**	**29.7%**	**29.7%**	**39.9%**	**11.9%**
TOTAL-NERC	**937,245**	**891,212**	**1,141,055**	**1,179,479**	**1,202,271**	**21.7%**	**25.8%**	**28.3%**	**15.0%**
EASTERN INTERCONNECTION	**662,537**	**623,812**	**790,247**	**828,671**	**838,851**	**19.3%**	**25.1%**	**26.6%**	**15.0%**
ERCOT INTERCONNECTION	**75,521**	**73,638**	**81,786**	**81,786**	**85,444**	**8.3%**	**8.3%**	**13.1%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,564**	**21,564**	**33,816**	**33,816**	**33,816**	**56.8%**	**56.8%**	**56.8%**	**9.7%**
WESTERN INTERCONNECTION	**169,093**	**163,721**	**263,900**	**263,900**	**271,876**	**56.1%**	**56.1%**	**60.8%**	**14.2%**

Table 22: Demand, Resources, and Reserve Margins – Winter 2018/2019

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	60,236	58,353	85,258	85,258	88,916	41.5%	41.5%	47.6%	13.75%
FRCC	52,088	48,269	65,851	66,417	66,417	26.4%	27.5%	27.5%	15.0%
MISO	80,778	72,959	109,739	126,881	126,881	35.9%	57.1%	57.1%	15.0%
MRO-MAPP	5,732	5,320	7,793	7,793	7,793	36.0%	36.0%	36.0%	15.0%
NPCC-New England (ISO-NE)	23,120	19,896	33,335	38,103	39,388	44.2%	64.8%	70.4%	15.0%
NPCC-New York (NYISO)	25,232	25,232	47,571	47,571	47,928	88.5%	88.5%	89.9%	15.5%
PJM	141,170	132,884	200,308	200,308	200,308	41.9%	41.9%	41.9%	15.0%
SERC-E	45,741	44,228	58,375	58,375	58,375	27.6%	27.6%	27.6%	15.0%
SERC-N	47,957	45,516	58,313	59,325	59,325	21.6%	23.7%	23.7%	15.0%
SERC-SE	49,773	47,467	70,985	74,216	74,216	42.6%	49.1%	49.1%	15.0%
SERC-W	22,468	21,658	32,048	41,555	41,555	42.6%	85.0%	85.0%	15.0%
SPP	44,306	43,200	69,413	74,066	75,516	56.7%	67.2%	70.4%	13.6%
WECC-BASN	13,119	12,814	16,452	16,452	17,550	25.4%	25.4%	33.8%	12.6%
WECC-CALN	19,911	19,627	36,066	36,066	36,541	81.1%	81.1%	83.5%	14.2%
WECC-CALS	25,331	23,688	52,388	52,388	52,890	106.8%	106.8%	108.8%	14.9%
WECC-DSW	19,964	19,719	32,296	32,296	36,059	61.8%	61.8%	80.6%	13.5%
WECC-NORW	31,430	31,365	38,329	38,329	38,394	22.0%	22.0%	22.2%	17.2%
WECC-ROCK	11,141	10,926	17,198	17,198	17,222	54.4%	54.4%	54.6%	12.5%
TOTAL-UNITED STATES	**719,496**	**683,120**	**1,031,720**	**1,072,599**	**1,085,276**	**43.4%**	**49.1%**	**50.8%**	**15.0%**
MRO-Manitoba Hydro	4,752	4,526	5,939	5,939	5,939	25.0%	25.0%	25.0%	12.0%
MRO-SaskPower	4,102	4,011	4,719	4,719	4,719	15.0%	15.0%	15.0%	13.0%
NPCC-Maritimes	5,587	5,249	7,263	7,263	7,263	30.0%	30.0%	30.0%	20.0%
NPCC-Ontario (IESO)	21,807	20,184	26,005	26,005	28,625	19.3%	19.3%	31.3%	20.0%
NPCC-Québec	40,372	39,272	46,065	46,065	46,065	14.1%	14.1%	14.1%	11.6%
WECC-AESO	13,919	13,856	16,084	16,084	17,438	15.6%	15.6%	25.3%	12.3%
WECC-BC	11,935	11,872	14,410	14,410	14,877	20.7%	20.7%	24.7%	12.3%
TOTAL-CANADA	**102,474**	**98,970**	**120,486**	**120,486**	**124,926**	**17.6%**	**17.6%**	**21.9%**	**10.0%**
TOTAL-MÉXICO	**1,995**	**1,995**	**3,374**	**3,374**	**3,579**	**69.1%**	**69.1%**	**79.4%**	**11.9%**
TOTAL-NERC	**823,965**	**784,084**	**1,155,580**	**1,196,458**	**1,213,781**	**40.2%**	**45.2%**	**47.3%**	**15.0%**
EASTERN INTERCONNECTION	**574,612**	**540,598**	**797,660**	**838,538**	**844,250**	**38.8%**	**45.9%**	**46.9%**	**15.0%**
ERCOT INTERCONNECTION	**60,236**	**58,353**	**85,258**	**85,258**	**88,916**	**41.5%**	**41.5%**	**47.6%**	**13.75%**
QUÉBEC INTERCONNECTION	**40,372**	**39,272**	**46,065**	**46,065**	**46,065**	**14.1%**	**14.1%**	**14.1%**	**9.7%**
WESTERN INTERCONNECTION	**146,512**	**143,692**	**249,925**	**249,925**	**257,783**	**70.6%**	**70.6%**	**75.9%**	**15.0%**

Table 23: Demand, Resources, and Reserve Margins - Summer 2019

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	76,577	74,612	81,868	81,868	86,230	6.9%	6.9%	12.6%	13.75%
FRCC	52,186	48,463	61,781	62,347	62,347	18.4%	19.5%	19.5%	15.0%
MISO	99,010	91,191	116,196	133,338	133,338	17.4%	34.7%	34.7%	15.0%
MRO-MAPP	5,863	5,737	7,213	7,213	7,213	23.0%	23.0%	23.0%	15.0%
NPCC-New England (ISO-NE)	30,875	27,476	32,639	35,648	36,933	5.7%	15.5%	19.6%	15.0%
NPCC-New York (NYISO)	34,533	32,480	46,819	46,819	47,073	35.6%	35.6%	36.3%	15.5%
PJM	172,780	163,801	200,990	200,990	206,723	16.3%	16.3%	19.6%	15.0%
SERC-E	48,229	46,010	57,122	57,122	57,122	18.4%	18.4%	18.4%	15.0%
SERC-N	50,937	47,410	57,132	58,074	58,074	12.2%	14.0%	14.0%	15.0%
SERC-SE	56,513	54,210	68,593	71,679	71,679	21.4%	26.8%	26.8%	15.0%
SERC-W	28,204	27,243	31,048	40,824	40,824	10.1%	44.7%	44.7%	15.0%
SPP	57,656	56,126	72,140	76,559	77,515	25.1%	32.8%	34.4%	13.6%
WECC-BASN	16,600	15,476	19,353	19,353	20,539	16.6%	16.6%	23.7%	12.6%
WECC-CALN	28,264	27,295	38,643	38,643	39,157	36.7%	36.7%	38.5%	14.2%
WECC-CALS	37,207	34,745	54,381	54,381	54,883	46.2%	46.2%	47.5%	14.9%
WECC-DSW	33,027	32,589	41,611	41,611	46,542	26.0%	26.0%	40.9%	13.5%
WECC-NORW	26,604	26,559	34,969	34,969	35,253	31.4%	31.4%	32.5%	17.2%
WECC-ROCK	13,102	12,765	16,914	16,914	17,252	29.1%	29.1%	31.7%	12.5%
TOTAL-UNITED STATES	**868,166**	**824,188**	**1,039,413**	**1,078,353**	**1,098,697**	**19.7%**	**24.2%**	**26.6%**	**15.0%**
MRO-Manitoba Hydro	3,334	3,107	5,075	5,075	5,165	52.2%	52.2%	54.9%	12.0%
MRO-SaskPower	3,708	3,617	4,353	4,353	4,353	17.4%	17.4%	17.4%	13.0%
NPCC-Maritimes	3,673	3,330	6,975	6,975	6,975	89.9%	89.9%	89.9%	20.0%
NPCC-Ontario (IESO)	21,980	20,383	23,649	23,649	27,034	7.6%	7.6%	23.0%	20.0%
NPCC-Québec	21,862	21,862	33,816	33,816	33,816	54.7%	54.7%	54.7%	11.6%
WECC-AESO	14,008	13,955	14,792	14,792	16,146	5.6%	5.6%	15.3%	12.3%
WECC-BC	8,663	8,610	10,440	10,440	11,181	20.5%	20.5%	29.1%	12.3%
TOTAL-CANADA	**77,228**	**74,864**	**99,099**	**99,099**	**104,669**	**28.3%**	**28.3%**	**35.5%**	**10.0%**
TOTAL-MÉXICO	**3,125**	**3,125**	**3,920**	**3,920**	**4,770**	**25.4%**	**25.4%**	**52.6%**	**11.9%**
TOTAL-NERC	**948,519**	**902,177**	**1,142,432**	**1,181,372**	**1,208,135**	**20.4%**	**24.5%**	**27.4%**	**15.0%**
EASTERN INTERCONNECTION	**669,481**	**630,585**	**791,725**	**830,665**	**842,366**	**18.3%**	**24.1%**	**25.8%**	**15.0%**
ERCOT INTERCONNECTION	**76,577**	**74,612**	**81,868**	**81,868**	**86,230**	**6.9%**	**6.9%**	**12.6%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,862**	**21,862**	**33,816**	**33,816**	**33,816**	**54.7%**	**54.7%**	**54.7%**	**9.7%**
WESTERN INTERCONNECTION	**172,125**	**166,697**	**263,809**	**263,809**	**273,675**	**53.3%**	**53.3%**	**59.0%**	**14.2%**

Table 24: Demand, Resources, and Reserve Margins – Winter 2019/2020

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	62,062	60,097	85,340	85,340	89,702	37.5%	37.5%	44.5%	13.75%
FRCC	52,784	48,929	66,153	66,719	66,719	25.3%	26.4%	26.4%	15.0%
MISO	81,577	73,758	111,302	128,444	128,444	36.4%	57.5%	57.5%	15.0%
MRO-MAPP	5,819	5,403	7,798	7,798	7,798	34.0%	34.0%	34.0%	15.0%
NPCC-New England (ISO-NE)	23,240	20,016	33,335	38,103	39,388	43.4%	64.0%	69.5%	15.0%
NPCC-New York (NYISO)	25,500	25,500	47,571	47,571	47,928	86.6%	86.6%	88.0%	15.5%
PJM	142,268	133,982	200,308	200,308	200,308	40.8%	40.8%	40.8%	15.0%
SERC-E	46,310	44,789	59,507	59,507	59,507	28.5%	28.5%	28.5%	15.0%
SERC-N	48,727	46,162	58,435	59,447	59,447	19.9%	22.0%	22.0%	15.0%
SERC-SE	50,501	48,186	70,973	74,188	74,188	40.5%	46.9%	46.9%	15.0%
SERC-W	22,924	22,118	31,587	41,620	41,620	37.8%	81.6%	81.6%	15.0%
SPP	44,256	43,179	69,779	74,432	75,881	57.7%	68.2%	71.5%	13.6%
WECC-BASN	13,334	13,029	16,304	16,304	17,486	22.3%	22.3%	31.1%	12.6%
WECC-CALN	20,267	19,975	32,957	32,957	33,459	62.6%	62.6%	65.1%	14.2%
WECC-CALS	25,779	24,085	52,371	52,371	52,873	103.2%	103.2%	105.1%	14.9%
WECC-DSW	20,371	20,126	31,920	31,920	35,905	56.7%	56.7%	76.3%	13.5%
WECC-NORW	31,724	31,659	38,612	38,612	38,756	21.7%	21.7%	22.2%	17.2%
WECC-ROCK	11,379	11,163	17,292	17,292	17,432	52.0%	52.0%	53.2%	12.5%
TOTAL-UNITED STATES	**728,822**	**692,155**	**1,031,545**	**1,072,933**	**1,086,843**	**41.5%**	**47.2%**	**49.1%**	**15.0%**
MRO-Manitoba Hydro	4,814	4,588	5,843	5,843	6,023	21.4%	21.4%	25.1%	12.0%
MRO-SaskPower	4,149	4,058	4,719	4,719	4,719	13.7%	13.7%	13.7%	13.0%
NPCC-Maritimes	5,587	5,254	7,258	7,258	7,258	29.9%	29.9%	29.9%	20.0%
NPCC-Ontario (IESO)	22,005	20,379	25,971	25,971	28,790	18.0%	18.0%	30.8%	20.0%
NPCC-Québec	40,586	39,486	46,065	46,065	46,065	13.5%	13.5%	13.5%	11.6%
WECC-AESO	14,299	14,236	16,070	16,070	17,424	12.4%	12.4%	21.9%	12.3%
WECC-BC	11,869	11,806	13,857	13,857	13,973	16.7%	16.7%	17.7%	12.3%
TOTAL-CANADA	**103,310**	**99,807**	**119,783**	**119,783**	**124,252**	**15.9%**	**15.9%**	**20.3%**	**10.0%**
TOTAL-MÉXICO	**2,081**	**2,081**	**3,345**	**3,345**	**3,650**	**60.7%**	**60.7%**	**75.4%**	**11.9%**
TOTAL-NERC	**834,213**	**794,044**	**1,154,673**	**1,196,061**	**1,214,745**	**38.4%**	**43.4%**	**45.6%**	**15.0%**
EASTERN INTERCONNECTION	**580,462**	**546,301**	**800,540**	**841,928**	**848,020**	**37.9%**	**45.0%**	**46.1%**	**15.0%**
ERCOT INTERCONNECTION	**62,062**	**60,097**	**85,340**	**85,340**	**89,702**	**37.5%**	**37.5%**	**44.5%**	**13.75%**
QUÉBEC INTERCONNECTION	**40,586**	**39,486**	**46,065**	**46,065**	**46,065**	**13.5%**	**13.5%**	**13.5%**	**9.7%**
WESTERN INTERCONNECTION	**149,409**	**146,529**	**249,922**	**249,922**	**258,506**	**67.3%**	**67.3%**	**73.0%**	**15.0%**

Table 25: Demand, Resources, and Reserve Margins - Summer 2020

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	77,826	75,771	81,958	81,958	86,320	5.3%	5.3%	10.9%	13.75%
FRCC	53,083	49,297	63,261	63,827	63,827	19.2%	20.2%	20.2%	15.0%
MISO	99,929	92,110	116,196	133,338	133,338	16.3%	33.4%	33.4%	15.0%
MRO-MAPP	5,946	5,818	7,215	7,215	7,215	21.3%	21.3%	21.3%	15.0%
NPCC-New England (ISO-NE)	31,215	27,816	32,639	35,648	36,933	4.6%	14.2%	18.3%	15.0%
NPCC-New York (NYISO)	34,867	32,814	46,819	46,819	47,073	34.3%	34.3%	35.0%	15.5%
PJM	174,458	165,479	200,990	200,990	206,723	15.2%	15.2%	18.5%	15.0%
SERC-E	48,904	46,673	56,998	56,998	56,998	16.6%	16.6%	16.6%	15.0%
SERC-N	51,718	48,073	58,510	59,452	59,452	13.1%	15.0%	15.0%	15.0%
SERC-SE	57,339	55,028	68,737	71,807	71,807	19.9%	25.2%	25.2%	15.0%
SERC-W	28,520	27,559	30,992	40,824	40,824	8.7%	43.1%	43.1%	15.0%
SPP	58,271	56,817	72,301	76,720	77,678	24.1%	31.7%	33.3%	13.6%
WECC-BASN	16,850	15,726	19,409	19,409	20,767	15.2%	15.2%	23.2%	12.6%
WECC-CALN	28,634	27,656	38,032	38,032	38,544	32.8%	32.8%	34.6%	14.2%
WECC-CALS	38,057	35,545	56,183	56,183	56,802	47.6%	47.6%	49.3%	14.9%
WECC-DSW	33,748	33,310	40,211	40,211	44,878	19.2%	19.2%	33.0%	13.5%
WECC-NORW	26,890	26,845	34,978	34,978	35,148	30.1%	30.1%	30.7%	17.2%
WECC-ROCK	13,387	13,056	17,090	17,090	17,727	27.7%	27.7%	32.4%	12.5%
TOTAL-UNITED STATES	**879,641**	**835,393**	**1,042,520**	**1,081,500**	**1,102,054**	**18.5%**	**22.9%**	**25.3%**	**15.0%**
MRO-Manitoba Hydro	3,410	3,183	4,825	4,825	5,365	41.5%	41.5%	57.3%	12.0%
MRO-SaskPower	3,757	3,666	4,353	4,353	4,353	15.9%	15.9%	15.9%	13.0%
NPCC-Maritimes	3,673	3,334	6,970	6,970	6,970	89.8%	89.8%	89.8%	20.0%
NPCC-Ontario (IESO)	22,015	20,416	24,492	24,492	26,977	11.3%	11.3%	22.5%	20.0%
NPCC-Québec	21,854	21,854	34,106	34,106	34,106	56.1%	56.1%	56.1%	11.6%
WECC-AESO	14,405	14,352	14,758	14,758	16,256	2.5%	2.5%	12.8%	12.3%
WECC-BC	8,607	8,554	10,179	10,179	11,031	18.3%	18.3%	28.2%	12.3%
TOTAL-CANADA	**77,721**	**75,359**	**99,682**	**99,682**	**105,057**	**28.3%**	**28.3%**	**35.2%**	**10.0%**
TOTAL-MÉXICO	**3,254**	**3,254**	**3,925**	**3,925**	**4,775**	**20.6%**	**20.6%**	**46.7%**	**11.9%**
TOTAL-NERC	**960,617**	**914,006**	**1,146,127**	**1,185,107**	**1,211,886**	**19.3%**	**23.4%**	**26.2%**	**15.0%**
EASTERN INTERCONNECTION	**677,105**	**638,084**	**795,298**	**834,278**	**845,532**	**17.5%**	**23.2%**	**24.9%**	**15.0%**
ERCOT INTERCONNECTION	**77,826**	**75,771**	**81,958**	**81,958**	**86,320**	**5.3%**	**5.3%**	**10.9%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,854**	**21,854**	**34,106**	**34,106**	**34,106**	**56.1%**	**56.1%**	**56.1%**	**9.7%**
WESTERN INTERCONNECTION	**175,011**	**169,530**	**261,212**	**261,212**	**271,298**	**49.3%**	**49.3%**	**55.0%**	**14.2%**

Table 26: Demand, Resources, and Reserve Margins – Winter 2020/2021

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	62,734	60,679	85,430	85,430	89,792	36.2%	36.2%	43.1%	13.75%
FRCC	53,415	49,535	68,617	69,183	69,183	28.5%	29.5%	29.5%	15.0%
MISO	82,393	74,574	111,302	128,444	128,444	35.1%	55.9%	55.9%	15.0%
MRO-MAPP	5,911	5,490	7,803	7,803	7,803	32.0%	32.0%	32.0%	15.0%
NPCC-New England (ISO-NE)	23,365	20,141	33,335	38,103	39,388	42.7%	63.1%	68.6%	15.0%
NPCC-New York (NYISO)	25,909	25,909	47,571	47,571	47,928	83.6%	83.6%	85.0%	15.5%
PJM	143,485	135,199	200,308	200,308	200,308	39.6%	39.6%	39.6%	15.0%
SERC-E	46,981	45,453	59,377	59,377	59,377	26.4%	26.4%	26.4%	15.0%
SERC-N	49,347	46,622	59,857	60,869	60,869	21.3%	23.3%	23.3%	15.0%
SERC-SE	51,377	49,052	71,119	74,334	74,334	38.4%	44.7%	44.7%	15.0%
SERC-W	23,193	22,385	31,225	41,322	41,322	34.6%	78.2%	78.2%	15.0%
SPP	44,870	43,826	70,104	74,756	76,210	56.2%	66.6%	69.8%	13.6%
WECC-BASN	13,515	13,210	15,527	15,527	17,310	14.9%	14.9%	28.1%	12.6%
WECC-CALN	20,535	20,236	35,851	35,851	36,326	74.6%	74.6%	76.9%	14.2%
WECC-CALS	26,307	24,561	53,724	53,724	54,343	104.2%	104.2%	106.6%	14.9%
WECC-DSW	20,773	20,528	30,492	30,492	35,210	46.8%	46.8%	69.5%	13.5%
WECC-NORW	32,035	31,970	39,004	39,004	40,154	21.8%	21.8%	25.3%	17.2%
WECC-ROCK	11,526	11,308	17,583	17,583	18,481	52.6%	52.6%	60.3%	12.5%
TOTAL-UNITED STATES	**737,670**	**700,676**	**1,038,230**	**1,079,682**	**1,096,783**	**40.7%**	**46.4%**	**48.7%**	**15.0%**
MRO-Manitoba Hydro	4,910	4,684	5,593	5,593	6,223	13.9%	13.9%	26.7%	12.0%
MRO-SaskPower	4,204	4,113	4,999	4,999	4,999	18.9%	18.9%	18.9%	13.0%
NPCC-Maritimes	5,578	5,250	7,254	7,254	7,254	30.0%	30.0%	30.0%	20.0%
NPCC-Ontario (IESO)	22,280	20,652	23,018	23,018	27,538	3.3%	3.3%	23.6%	20.0%
NPCC-Québec	40,671	39,571	46,355	46,355	46,355	14.0%	14.0%	14.0%	11.6%
WECC-AESO	14,750	14,687	16,088	16,088	17,586	9.1%	9.1%	19.2%	12.3%
WECC-BC	11,799	11,736	14,035	14,035	14,555	19.0%	19.0%	23.4%	12.3%
TOTAL-CANADA	**104,192**	**100,692**	**117,341**	**117,341**	**124,509**	**12.6%**	**12.6%**	**19.5%**	**10.0%**
TOTAL-MÉXICO	**2,167**	**2,167**	**3,526**	**3,526**	**4,376**	**62.7%**	**62.7%**	**101.9%**	**11.9%**
TOTAL-NERC	**844,029**	**803,535**	**1,159,098**	**1,200,550**	**1,225,669**	**37.3%**	**42.2%**	**45.2%**	**15.0%**
EASTERN INTERCONNECTION	**587,218**	**552,883**	**801,483**	**842,935**	**851,181**	**36.5%**	**43.5%**	**45.0%**	**15.0%**
ERCOT INTERCONNECTION	**62,734**	**60,679**	**85,430**	**85,430**	**89,792**	**36.2%**	**36.2%**	**43.1%**	**13.75%**
QUÉBEC INTERCONNECTION	**40,671**	**39,571**	**46,355**	**46,355**	**46,355**	**14.0%**	**14.0%**	**14.0%**	**9.7%**
WESTERN INTERCONNECTION	**151,965**	**149,024**	**252,962**	**252,962**	**264,025**	**66.5%**	**66.5%**	**73.7%**	**15.0%**

Table 27: Demand, Resources, and Reserve Margins - Summer 2021

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	78,927	76,864	81,966	81,966	86,328	3.9%	3.9%	9.4%	13.75%
FRCC	53,842	50,056	64,128	64,694	64,694	19.1%	20.2%	20.2%	15.0%
MISO	100,928	93,109	116,196	133,338	133,338	15.1%	32.1%	32.1%	15.0%
MRO-MAPP	6,035	5,905	7,217	7,217	7,217	19.6%	19.6%	19.6%	15.0%
NPCC-New England (ISO-NE)	31,559	28,160	32,639	35,648	36,933	3.4%	13.0%	17.0%	15.0%
NPCC-New York (NYISO)	35,192	33,139	46,819	46,819	47,073	33.0%	33.0%	33.8%	15.5%
PJM	176,060	167,081	200,990	200,990	206,723	14.2%	14.2%	17.4%	15.0%
SERC-E	49,640	47,400	56,881	56,881	56,881	14.6%	14.6%	14.6%	15.0%
SERC-N	52,189	48,495	58,559	59,501	59,501	12.2%	14.0%	14.0%	15.0%
SERC-SE	58,359	56,042	68,743	71,813	71,813	17.8%	23.1%	23.1%	15.0%
SERC-W	28,809	27,840	30,276	40,532	40,532	5.1%	40.7%	40.7%	15.0%
SPP	58,948	57,526	72,870	77,288	78,267	23.6%	31.1%	32.8%	13.6%
WECC-BASN	17,070	15,946	19,413	19,413	20,889	13.7%	13.7%	22.4%	12.6%
WECC-CALN	29,106	28,128	38,033	38,033	38,545	30.7%	30.7%	32.4%	14.2%
WECC-CALS	38,947	36,385	56,090	56,090	56,709	44.0%	44.0%	45.6%	14.9%
WECC-DSW	34,336	34,193	39,911	39,911	44,562	16.2%	16.2%	29.8%	13.5%
WECC-NORW	27,190	27,145	34,971	34,971	35,142	28.6%	28.6%	29.2%	17.2%
WECC-ROCK	13,677	13,352	17,082	17,082	17,718	24.9%	24.9%	29.5%	12.5%
TOTAL-UNITED STATES	**890,814**	**846,766**	**1,042,783**	**1,082,188**	**1,102,865**	**17.1%**	**21.5%**	**23.8%**	**15.0%**
MRO-Manitoba Hydro	3,472	3,245	4,600	4,600	5,230	32.5%	32.5%	50.6%	12.0%
MRO-SaskPower	3,837	3,746	4,601	4,601	4,601	19.9%	19.9%	19.9%	13.0%
NPCC-Maritimes	3,676	3,342	6,965	6,965	6,965	89.5%	89.5%	89.5%	20.0%
NPCC-Ontario (IESO)	22,142	20,540	22,520	22,520	26,704	1.7%	1.7%	20.6%	20.0%
NPCC-Québec	21,854	21,854	34,106	34,106	34,106	56.1%	56.1%	56.1%	11.6%
WECC-AESO	14,795	14,742	14,731	14,731	16,373	-0.4%	-0.4%	10.7%	12.3%
WECC-BC	8,690	8,637	10,178	10,178	10,985	17.1%	17.1%	26.4%	12.3%
TOTAL-CANADA	**78,466**	**76,106**	**97,700**	**97,700**	**104,964**	**24.5%**	**24.5%**	**33.8%**	**10.0%**
TOTAL-MÉXICO	**3,389**	**3,389**	**3,925**	**3,925**	**4,775**	**15.8%**	**15.8%**	**40.9%**	**11.9%**
TOTAL-NERC	**972,668**	**926,261**	**1,144,409**	**1,183,813**	**1,212,604**	**17.7%**	**21.7%**	**24.7%**	**15.0%**
EASTERN INTERCONNECTION	**684,687**	**645,626**	**794,003**	**833,407**	**846,471**	**16.0%**	**21.7%**	**23.6%**	**15.0%**
ERCOT INTERCONNECTION	**78,927**	**76,864**	**81,966**	**81,966**	**86,328**	**3.9%**	**3.9%**	**9.4%**	**13.75%**
QUÉBEC INTERCONNECTION	**21,854**	**21,854**	**34,106**	**34,106**	**34,106**	**56.1%**	**56.1%**	**56.1%**	**9.7%**
WESTERN INTERCONNECTION	**177,123**	**171,893**	**260,940**	**260,940**	**271,164**	**47.3%**	**47.3%**	**53.1%**	**14.2%**

Table 28: Demand, Resources, and Reserve Margins - Winter 2021/2022

Country / Assessment Area	Demand		Capacity Resouces			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
ERCOT	63,408	61,345	85,438	85,438	89,800	34.7%	34.7%	41.6%	13.75%
FRCC	54,037	50,157	68,617	69,183	69,183	27.0%	28.0%	28.0%	15.0%
MISO	83,217	75,398	111,302	128,444	128,444	33.7%	54.3%	54.3%	15.0%
MRO-MAPP	5,997	5,570	7,808	7,808	7,808	30.2%	30.2%	30.2%	15.0%
NPCC-New England (ISO-NE)	23,491	20,266	33,335	38,103	39,388	41.9%	62.2%	67.7%	15.0%
NPCC-New York (NYISO)	26,210	26,210	47,571	47,571	47,928	81.5%	81.5%	82.9%	15.5%
PJM	144,621	136,335	200,308	200,308	200,308	38.5%	38.5%	38.5%	15.0%
SERC-E	47,638	46,102	59,260	59,260	59,260	24.4%	24.4%	24.4%	15.0%
SERC-N	50,043	47,058	60,115	61,127	61,127	20.1%	22.1%	22.1%	15.0%
SERC-SE	52,295	49,963	71,126	74,341	74,341	36.0%	42.2%	42.2%	15.0%
SERC-W	23,490	22,670	30,363	40,884	40,884	29.3%	74.0%	74.0%	15.0%
SPP	45,331	44,320	74,259	78,912	80,397	63.8%	74.1%	77.4%	13.6%
WECC-BASN	13,702	13,397	15,527	15,527	17,503	13.3%	13.3%	27.7%	12.6%
WECC-CALN	20,884	20,585	35,852	35,852	36,327	71.7%	71.7%	73.9%	14.2%
WECC-CALS	26,783	24,987	53,762	53,762	54,381	100.7%	100.7%	103.0%	14.9%
WECC-DSW	21,132	20,887	30,494	30,494	35,230	44.3%	44.3%	66.7%	13.5%
WECC-NORW	32,483	32,418	39,540	39,540	40,722	21.7%	21.7%	25.4%	17.2%
WECC-ROCK	11,768	11,549	17,624	17,624	18,640	49.8%	49.8%	58.4%	12.5%
TOTAL-UNITED STATES	**746,528**	**709,217**	**1,042,302**	**1,084,178**	**1,101,672**	**39.6%**	**45.2%**	**47.6%**	**15.0%**
MRO-Manitoba Hydro	4,992	4,766	5,368	5,368	5,998	7.5%	7.5%	20.1%	12.0%
MRO-SaskPower	4,294	4,203	4,999	4,999	4,999	16.4%	16.4%	16.4%	13.0%
NPCC-Maritimes	5,579	5,255	7,250	7,250	7,250	29.9%	29.9%	29.9%	20.0%
NPCC-Ontario (IESO)	22,616	20,985	24,025	24,025	27,544	6.2%	6.2%	21.8%	20.0%
NPCC-Québec	40,968	39,868	46,355	46,355	46,355	13.1%	13.1%	13.1%	11.6%
WECC-AESO	15,315	15,252	16,083	16,083	17,725	5.0%	5.0%	15.7%	12.3%
WECC-BC	12,077	12,014	14,343	14,343	14,863	18.8%	18.8%	23.1%	12.3%
TOTAL-CANADA	**105,842**	**102,343**	**118,422**	**118,422**	**124,734**	**11.9%**	**11.9%**	**17.8%**	**10.0%**
TOTAL-MÉXICO	**2,257**	**2,257**	**3,526**	**3,526**	**4,376**	**56.2%**	**56.2%**	**93.9%**	**11.9%**
TOTAL-NERC	**854,627**	**813,816**	**1,164,250**	**1,206,126**	**1,230,782**	**36.2%**	**41.1%**	**44.0%**	**15.0%**
EASTERN INTERCONNECTION	**593,850**	**559,258**	**805,706**	**847,582**	**854,860**	**35.7%**	**42.7%**	**44.0%**	**15.0%**
ERCOT INTERCONNECTION	**63,408**	**61,345**	**85,438**	**85,438**	**89,800**	**34.7%**	**34.7%**	**41.6%**	**13.75%**
QUÉBEC INTERCONNECTION	**40,968**	**39,868**	**46,355**	**46,355**	**46,355**	**13.1%**	**13.1%**	**13.1%**	**9.7%**
WESTERN INTERCONNECTION	**154,674**	**151,927**	**253,301**	**253,301**	**264,762**	**63.8%**	**63.8%**	**71.2%**	**15.0%**

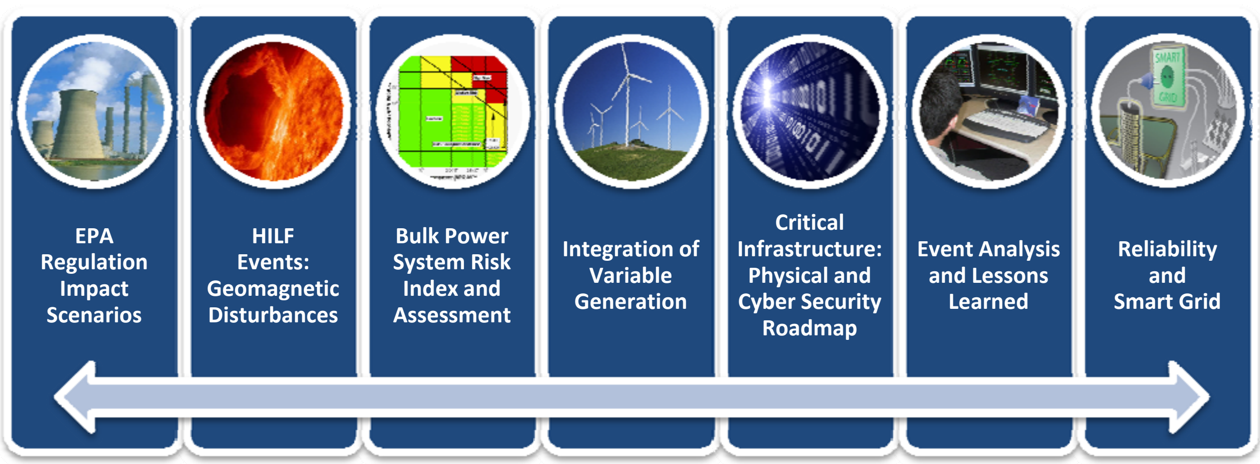
Emerging and Standing Reliability Issues

The NERC Reliability Assessment and Performance Analysis (RAPA) program reviews, assesses, and reports on the overall electric reliability of the interconnected bulk power system in North America. As part of this assessment, the program identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes. NERC reliability assessments are performed based on data supplied by users, owners, and operators of the bulk power system and gathered by the eight Regional Entities. This "bottom up" approach ensures that local and Regional issues are accounted for and their relevance understood.

Each year, the NERC *Long-Term Reliability Assessment* forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes expected to take effect throughout the ten-year timeframe assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. A set of scenarios can then be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure and identify any significant changes to the bulk power system that may be required to maintain reliability. For this reason, NERC investigated each of these issues through structured technical committees and leveraged the expertise of the electric industry's broad knowledge base.

Over the next decade, the electric industry will face a number of significant emerging reliability issues. The confluence of these issues will drive a transformational change for the industry, potentially resulting in a dramatically different resource mix, a new market for emissions trading, a need for enhanced modeling, and a new risk framework built to address growing critical infrastructure and protection concerns—both physical and cyber. Each of these elements of change is critically interdependent and industry action must be closely coordinated to ensure reliability. As a result, numerous NERC activities are currently on-going, exemplifying the industry's commitment to understand, resolve, and make recommendations that support enhancing future reliability (Figure 40).

Figure 40: On-Going NERC Activities



2010 Emerging Reliability Issues Update

The *2010 NERC Long-Term Reliability Assessment*[81] identified a number of significant emerging reliability issues that the electric industry could be challenged with over the 10-year time horizon (2010-2019). Each of these elements of change can be critically interdependent and industry action must be closely coordinated to ensure reliability. The following 2010 Emerging Reliability Issues were identified by the Reliability Assessment Subcommittee (RAS)[82] of the NERC Planning Committee (PC).[83] Progress made since the *2010 Long-Term Reliability Assessment* is shown below (Table 29).

Table 29: 2010 Long-Term Reliability Assessment Emerging Issues

Issue	Progress Since 2010 LTRA	Group Assigned
Impacts of Resource Mix Changes to System Stability and Frequency Response	IVGTF Report: *Operating Practices, Procedures and Tools* IVGTF Report: *Ancillary Service and Balancing Area Solutions to Integrate Variable Generation* IVGTF Report: *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Planning Adequacy Planning*	Integration of Variable Generation Task Force (IVGTF) of the NERC Planning Committee
Changing Resource Mix	IVGTF Report: *Operating Practices, Procedures and Tools* IVGTF Report: *Ancillary Service and Balancing Area Solutions to Integrate Variable Generation* IVGTF Report: *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Planning Adequacy Planning*	Integration of Variable Generation Task Force (IVGTF) of the NERC Planning Committee
Diminishing Frequency Response	NERC and the Regional Entities continue to participate in the development of a frequency response standard.	Frequency Response Initiative
Transmission Operations with Vital Transmission out of Service during Upgrades	Transmission Issues Subcommittee	Transmission Issues Subcommittee of the NERC Planning Committee
Uncertainty of Sustained Participation in Demand Response Programs	Demand Response Availability Data System launched October 4, 2011	Demand Response Data Task Force of the NERC Planning Committee
Consistent Modeling of Remote Resources	NERC and Regional Entity Engagement in modeling development and improvement processes	ERO-RAPA and Model Validation Task Force

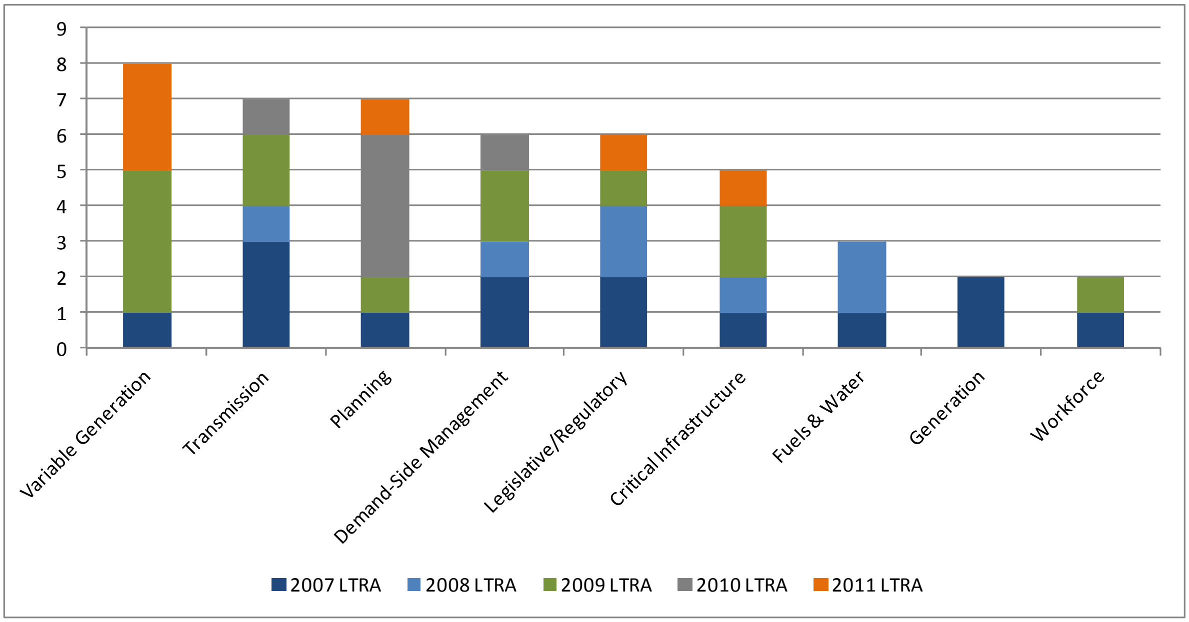
81 NERC 2010 LTRA http://www.nerc.com/files/2010_LTRA_v2-.pdf.

82 The 2011 Roster of the Reliability Assessment Subcommitteehttp://www.nerc.com/files/roster.pdf.

83 The 2010-2012 Roster of the NERC Planning Committee http://www.nerc.com/docs/pc/Planning_Committee_Membership_2010-2012_04-25-11.pdf.

NERC undertook an additional step in 2011 to classify Emerging Issues from 2007 through 2011 into high-level categories to develop an overall trend and highlight the issues that the electric industry identifies as important topics (Figure 41). The values on the y-axis represent the number of emerging and standing reliability issues raised in prior assessments.

Figure 41: 2007 – 2011 Classification of Emerging Issues



While in some cases, priorities have shifted, variable generation integration, transmission, and planning challenges consistently appear as the top issues. Additionally, demand-side and legislative or regulatory issues are more apparent in recent reliability assessments, but continue to be some of the top priorities of the industry in its pursuit to address emerging reliability trends. This graph is a new addition to for this *2011 Long-Term Reliability Assessment* and will be continued in subsequent publications of this report to show the 5-year trend of Emerging Issue identification and selection by Planning Committee members.

Risk Assessment

The assessment of risk from standing and emerging reliability issues measures their perceived likelihood of occurrence and potential consequences to reliability of the bulk power system. To qualify for consideration, emerging reliability issues must affect bulk power system reliability based on the following criteria:

- Exists for more than a single year in the ten-year study time horizon
- Impacts reliability no sooner than three years into the future to allow for sufficient assessment and analysis
- Impacts reliability across at least one Regional Entity footprint and is not a local or subregional reliability issue.

RAS identified six issues for use in the 2011 Planning Committee Risk Assessment (Figure 42). During the June 7-8, 2011 NERC Planning Committee meeting in Toronto, Ontario, [84] the committee reviewed and approved Emerging Reliability Issues for review and further analysis by NERC in this assessment. A risk assessment was performed on these issues and detailed in the next section. After this approval, the voting members of the Planning Committee prioritized the resulting issues based on risk, defined as their likelihood of occurrence and consequence, and categorized each issue as high impact, medium impact, or low impact to reliability. This risk assessment evaluated two timeframes: the risk to the bulk power system in the next 1 to 5 years (2011-2015), and the risk to the bulk power system in the next 6 to 10-years (2016-2020).

Figure 42: 2011 Emerging Reliability Issues

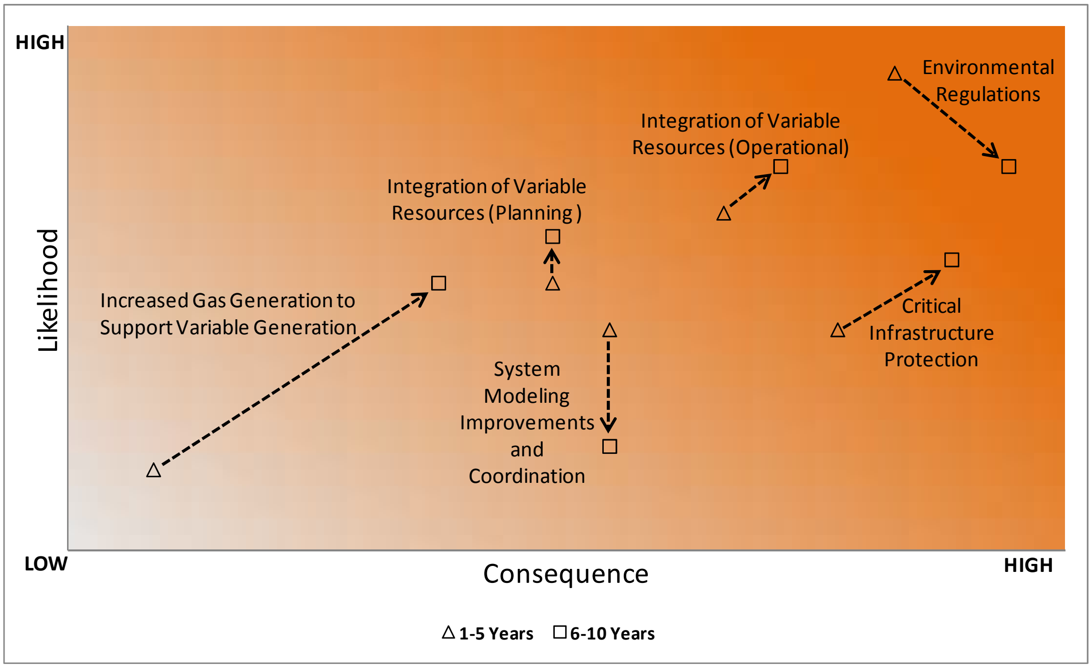
- Environmental Regulations and Impacts to BPS Reliability
- Integration of Variable Generation (Operational)
- Critical Infrastructure Protection
- Integration of Variable Generation (Planning)
- System Modeling Improvement and Coordination
- Increased Gas Generation to Support Variable Generation

Risk Ranking and Evolution

The risk vectors for each of the emerging reliability issues for both the one to five (1-5) year and six to ten (6-10) year timeframes are shown below (Figure 43). Risk vectors for the 1-5 year timeframe are represented by a blue diamond—the 6-10-year risk vectors are represented by the red square. With this perspective, relative risk of each issue is determined based on the Planning Committee survey results. Shifts in relative risk can be determined by evaluating the change between the two time periods.

[84] http://www.nerc.com/docs/pc/UPDATED_PC%20Agenda_June_%202011%20v6_CompletePkg.pdf.

Figure 43: Risk Ranking and Evolution



Issues identified in the upper-right quadrant of the figure are considered to be high-likelihood of occurrence and high-consequence to the reliability of the bulk power system. This risk assessment is performed each year and act as a platform to inform stakeholders, regulators, policy makers and the general public what issues NERC believes need to be most critically addressed.

By identifying these issues, a detailed special reliability assessment can be completed to further understand the implications to reliability. Scenario analysis can also be performed assessing the robustness of the reference case against the scenario results, and determine how the issues affect bulk power system reliability. The most recent example is the NERC 2010 Special Reliability Assessment on resource adequacy impacts from potential environmental regulations.[85] In 2009, environmental regulations were determined to be a high risk reliability issue; therefore, in 2010, NERC completed detailed analysis to model what the potential affects could be to resource adequacy.

Environmental Regulations are shown to be the number one risk to reliability over the next 1 to 5 years. Going forward in the long-term, some issues become more risky due to technical and policy challenges, as well as uncertainties associated with determining solutions. These uncertainties continue to stress the planning functions, and will affect industry's ability to operate the system in a reliable manner. In the face of accommodating large amounts of variable generation, the changing landscape of planning and operating the bulk power system must be finely tuned. Through the course of operator experience and implementing enhanced planning techniques, reliability will ultimately be maintained. For this reason, NERC pays considerable attention to these emerging and standing issues to ensure reliability is not diminished.

[85] http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

Environmental Regulations and Impacts to Bulk Power System Reliability

Rules and proposed regulations from the United States Environmental Protection Agency may impact the reliability of the bulk power system if not strategically managed.

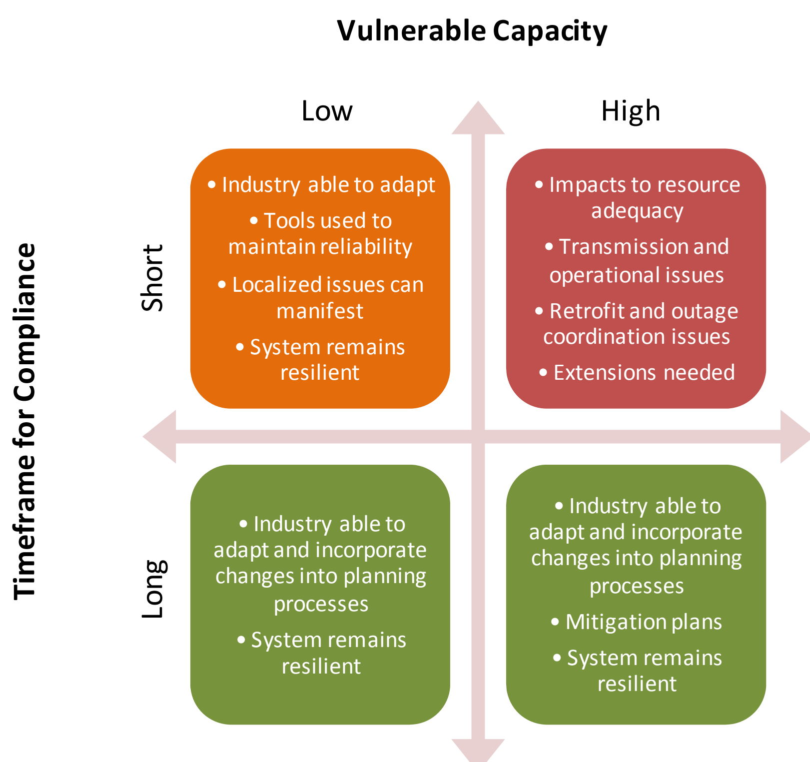
Issue Assignment

- NERC Planning Committee (PC)
- NERC Reliability Assessment Subcommittee (RAS)

Risk Assessment

- High-Likelihood, High-Consequence in 1 to 5 and 6 to 10-year timeframe
- Risk is primarily dependent on the amount of vulnerable capacity within a given area and the timeframe for compliance (Figure 44)

Figure 44: Environmental Regulations and Impacts to Bulk Power System Reliability Risk Matrix



Background

In 2011, several regulations are in the process of being proposed or implemented by the U.S. Environmental Protection Agency (EPA). These rules and proposed regulations as currently drafted would directly impact the electric industry within the United States.[86] Depending on the outcome of any

[86] The NERC Reliability Functional Model defines the set of functions that must be performed to ensure the reliability of the bulk electric system. http://www.nerc.com/page.php?cid=2%7C247%7C108.

or all of these potential regulations, the results could accelerate the retirement of a significant number of fossil-fired power plants. Additionally, the U.S. EPA is developing rules that would mandate existing power suppliers to either retrofit environmental controls at existing generating plants or retire them. The most significant proposed EPA rules, the Maximum Achievable Control Technology Rule (MACT) and the Cross State Air Pollution Rule (CSAPR) have been in development for over 10-years and are currently undergoing court-ordered revisions that must be implemented within mandatory timeframes. The four regulations assessed are:

1. Clean Water Act – Section 316(b), Cooling Water Intake Structures
2. Title I of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP), or Maximum Achievable Control Technology (MACT) Standards
3. Cross State Air Pollution Rule (CSAPR) which has replaced the Clean Air Transport Rule (CATR)
4. Coal Combustion Residuals (CCR)

A significant amount of generation retirements and de-rates associated with environmental controls may severely impact Planning Reserve Margins. Early retirement of multiple units in the short-run can stress the bulk power system if plans are not in place to add additional resources to cover the loss of generation from facilities affected by EPA regulations. An event such as this can affect both short- and long-term planning strategies and reduce Planning Reserve Margins. Load pocket areas (i.e., major metropolitan areas) will be more affected by the loss of "critical" bulk power resources that may be supplying more than just capacity to the power system.

With fewer resources, the flexibility of the system is reduced and the risk of a capacity shortage may increase, unless additional resources are available. In areas where the Planning Reserve Margins fall below the NERC Reference Margin Level or state mandated requirements, resources may not be sufficient to meet future demands.

Construction of new generation may be necessary to support reliability goals and targets in assessment areas. In some cases, existing generation sites can and will be used to upgrade or construct replacement generation—in other locations, new greenfield generation sites may need to be developed. Each situation will have unique characteristics that determine how long the siting and permitting process may last. This is of particular importance to the resource assessment due to the constricted compliance timelines associated with the potential rules.

As replacement generation is constructed, new transmission infrastructure may be required to interconnect these new generation resources. Transmission impacts need to be assessed and also given ample time for preventative measures to be put in place. Additionally, existing generation resources may not be deliverable due to transmission limitations in the existing system and enhancements may be needed in order to support Firm and reliable transmission service. Transmission system enhancements and reconfiguration may be necessary in some areas, which may create additional timing issues as new transmission facilities take longer to plan, design, and construct compared to generation facilities. While new facilities are under construction, impacts such as reduced system stability, tighter flexibility margins, and problems with deliverability of resources may be experienced.

Along with other drivers, potential environmental regulations can change the overall generation fuel-mix, which may change the inherent operating characteristics of a given resource portfolio. For example, with less coal-fired generation capacity, more gas-fired generation may need to operate to provide base-load services. As a result, the interdependency of gas and electric supply, transport, and delivery must be further assessed to ensure reliability is not degraded.

Reliability Impact

There are four main reliability impacts of the EPA environmental regulations. First, a significant amount of generation retirements and de-rates associated with environmental controls may severely impact Reserve Margins if replacement resources cannot be built or acquired by proposed deadlines. Reserve Margins are a measure of available capacity above the capacity required to meet normal peak demand levels. Most regulatory bodies and planning entities require maintaining a Planning Reserve Margin of 10-20 percent of peak demand to provide flexibility to operators against breakdowns in production or sudden increases in energy demand. Mechanisms must be in place to ensure required reliability units can provide the grid with support until other resources are put in place (*e.g.,* generation or transmission).

The industry must consider all EPA regulatory requirements in an integrated fashion when making technology investments or retirement decisions. Further, outages at one generating unit must be compensated for by increased generation elsewhere. Therefore, the loss of reliability support functions provided by coal-fired generation may not be easily replaced given the time constraints. Studies demonstrate that regional reserve requirements could be compromised by the cumulative impact of EPA's actions, which indicate that between 2012 and 2018, the nation's power grid will be stressed in ways never before experienced and could pose a reliability concern.

If the EPA intends to move forward with the implementation of the MACT rule as proposed in March 2011, the electric industry will need time to comply. Mechanisms must be in place to ensure required reliability units can provide the grid with support until alternative resources are put in place (*e.g.,* generation or transmission).

MACT, as proposed, would require the reduction of hazardous air pollutant (HAP) emissions from institutional, commercial, and industrial boilers. It would apply to boilers located at "major" sources of HAPs, those emitting 10 tons per year or more of a single HAP or 25 tons per year of any combination of HAPs. Under the Act, the Administrator of the EPA may grant one-year compliance extensions where necessary for the installation of controls. EPA may also exercise enforcement discretion to grant additional extensions where needed to preserve system reliability. In extraordinary cases, the President of the United States may grant compliance extensions if the "technology to implement such standard is not available" and "national security interests" are threatened. These authorities should be used to provide extensions, where justified, to ensure the system remains reliable.

Second, EPA regulations may result in the potential loss of a significant amount of generation, either through retirements or de-rates associated with powering on-site environmental controls equipment, during a short time frame (2012-2015). Within this timeframe, some generators may not have enough time to acquire permits, engineering, equipment design, acquisition of equipment, and systematically shut down their units to install the necessary retrofitted equipment, while concurrently meeting reliability goals. Again, existing legal authorities should be used to provide extensions where justified.

Third, unit outages for maintenance due to retrofits will affect both the capability to retrofit existing plants to meet required emission targets and the ability of industry to coordinate the necessary outages in order to perform the retrofit. For example, to meet the CSAPR rule, one possible retrofit solution is to install an air scrubber. It takes approximately 18 months, including planning and installation, for an air scrubber to be installed into an existing facility as scrubbing equipment is unique to each generating.

Finally, there are a limited number of companies available to design, manufacture, and install scrubbers, which will create a queued list in each phase, potentially increasing the lead time for some units beyond 18 months. This constraint should be considered when determining compliance deadlines.

Resource Adequacy Considerations

Retirement dates of units may be accelerated to comply with the implementation of the rules. Early retirements of multiple units can stress the bulk power system in the short-run if plans are not in place to respond. This will affect both short- and long-term planning strategies and may affect Planning Reserve Margins. In areas where Planning Reserve Margins fall below targets or requirements, resources in a specific area may not be sufficient to meet future demands. However, tools and actions for mitigating resource adequacy issues include the following:

1. **Advancing in-service dates of future or *Conceptual* resources:** generation resources may be able to advance their in-service dates where sufficient lead time is given. Existing market tools, such as forward capacity markets and reserve sharing mechanisms, can assist in signaling resource needs.
2. **Addition of new resources not yet proposed:** smaller, combustion turbines or mobile generation units can be added to maintain local reliability where additional capacity is needed. Additional distributed generation may also mitigate local reliability issues.
3. **Increase in transfers:** Regions/subregions that have access to a larger pool of generation may be able to increase the amount of import capacity from areas with available capacity, transfer capability is sufficient and deliverability is confirmed. Additional transmission or upgrades may enable additional transactions to provide additional resources across operating boundaries.
4. **Increased demand-side management and Conservation:** increased Energy Efficiency may offset future demand growth. Increasing available Demand Response resources can provide planning and operating flexibility by reduced peak demand.
5. **Early action to mitigate severe losses:** Planning and constructing retrofits immediately will aid in preventing the potential for construction delays and overflows, mitigating the risk of additional unit loss. Managing retrofit timing on a unit basis will keep capacity supply by region stable. Historically, when some compliance targets have been missed, the EPA has recognized early efforts that demonstrate industry's willingness to comply.

6. **Developing or exploring newer technologies:** Other technologies exist, (*i.e.,* trona injection) which will allow companies to comply with EPA air regulations without installing more scrubbers.
7. **Use of more gas-fired generation:** Existing gas units may have had additional power production potential, which can be expanded during off-peak periods. This capacity can assist in managing plant outages during the installation of emission control systems.
8. **Repowering of coal-fired generation:** Some coal-fired generation have the potential to repower their units with combined-cycle gas turbines and reducing emissions.

Transmission Adequacy Impacts

New transmission infrastructure may be required to support system reliability in local areas and interconnect new electricity generation to meet reliability requirements. Additionally, existing generation may not be deliverable unless system reinforcements are added. The origin and extent of these limits differ depending on a number of variables (such as the length of the line). Transmission system enhancements and reconfiguration may be necessary in some areas, thus requiring scheduling flexibility because new transmission facilities may take relatively longer to construct than generation. Second tier effects may include impacts to system stability, reduced flexibility, and deliverability of resources.

Resource Siting Impacts

Additional generation siting may be necessary to support the build-out of new replacement generation. In some cases, existing sites will be used while for others new greenfield sites will need to be developed. Each situation will have unique characteristics that determine how long the permitting, budgeting and building processes may actually require. This is of particular importance to the resource assessment due to the constricted compliance timelines associated with the potential rules.

Operations Impacts

Along with other drivers, potential environmental regulations can change the overall fuel-mix, ultimately changing the inherent operating characteristics of a given resource portfolio. For example, with less coal-fired capacity, more gas-fired generation may need to provide base-load services. As a result, the interdependency of gas and electric supply, transport, and delivery must be assessed to ensure reliability is not degraded. The combination of this growth in gas demand within the electric sector and its changing status among the gas consuming sectors has increased significantly the interdependences of the two industries, and caused many within both industries to focus more sharply on the interface between the two industries. A key element of this focus on the interface between the two industries is the need for increased coordination between the two industries, particularly at a regional level.[87]

[87] 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States report: http://www.nerc.com/page.php?cid=4|61, December 2011

Follow on Actions and Recommendations

- An updated analysis to the 2010 assessment is provided in the *Potential Impacts of Environmental Regulations Update* section of this report.[88]
- In 2011, NERC will issue a special assessment that studies the interdependency between natural gas production, transportation, and its use as a generation fuel for the electric industry.[89] A follow-on assessment, to be published in 2012, will study gas-electric interdependency vulnerabilities.
- In 2012, once all rules have been finalized, NERC will again update its study to reflect the state of regulations.

[88] 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf.

[89] Draft 2011 NERC Special Assessment – Gas Summary: http://www.nerc.com/docs/pc/Draft_2011_Special_Assessment-Gas_Summary_redline.pdf.

Integration of Variable Generation (System Operations Perspective)

The integration of variable generation assets into real-time operations continues to pose challenges to reliability as additional variable generation resources introduce non-traditional operating characteristics to the bulk power system.

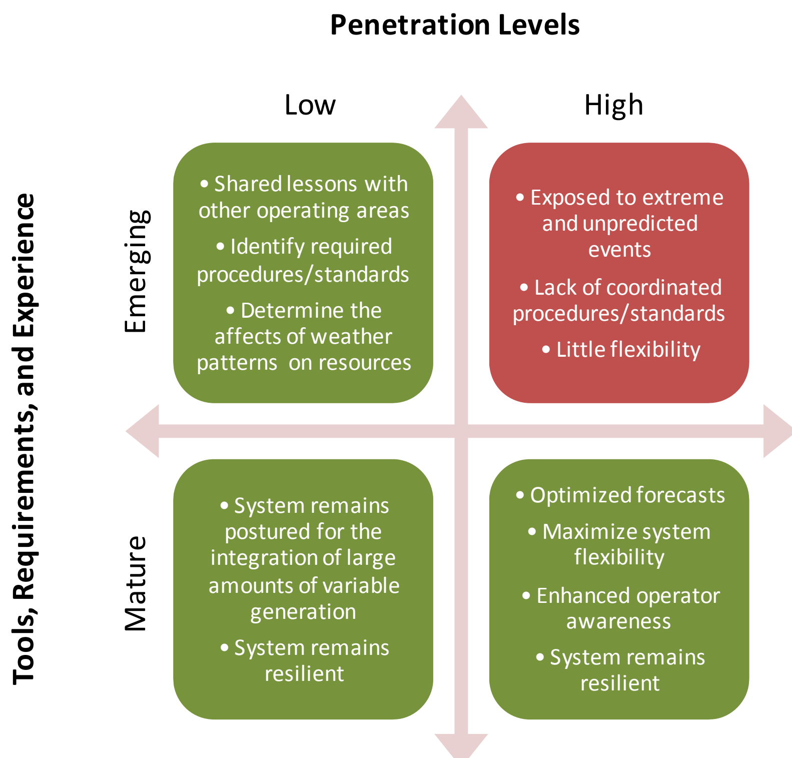
Issue Assignment

- NERC Planning Committee – Integration of Variable Generation Task Force (IVGTF)[90]

Risk Assessment

- High-Likelihood, High-Consequence in 1 to 5 and 6 to 10-year timeframe
- Risk is primarily dependent on level of penetration and the maturity of tools, requirements and operator experience within a given area (Figure 45)

Figure 45: Integration of Variable Generation (System Operations Perspective) Risk Matrix



Background

The expected increase in variable generation additions on the bulk power system will raise the level of uncertainty that a system operator must factor into real-time operating decisions. To manage this increased uncertainty, system operators must have access to advanced variable generation forecasting techniques and sufficient flexible resources to mitigate the added variability and uncertainty associated

[90] The NERC Planning Committee Integration of Variable Generation Task Force: http://www.nerc.com/filez/ivgtf.html.

with the large scale variable generation assets. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools must be enhanced to assist operators in maintaining bulk power system reliability.

Forecasting

Forecasting techniques must be incorporated into day-to-day operational planning and real-time operations routines and practices including unit commitment and dispatch. Forecasting of variable generation resources is important in all timeframes, and there are many uses for longer-range forecasts from days and weeks (e.g., transmission outage planning and minimum generation issues) to years (e.g., integrated resource planning, where resource flexibility and ramping capabilities should be increasingly valued, and the generation mix if not appropriately planned can raise bigger challenges/issues during operating timeframe). Such longer-term schedules are adjusted as they get closer to real-time and the critical operating impacts to bulk power system reliability tend to be closer to real-time. Therefore, forecasting requirements for the coming 48 hours are particularly important.

In concert with industry stakeholders, NERC has identified several conclusions have been developed about wind forecasting techniques and challenges that should be considered:

- Timely delivery of this information must be transferred to the system operator in a useful and actionable way. A forecast can better inform operator about changes on the system, but does not change the system balance. A forecast provides value only when operators can receive the information in a manner that is useful, and have the necessary resources and mechanisms in place that enable them to take actions in response to the forecast.
- Aggregate forecast accuracy improves with the size of the region forecast and aggregation across broad geographical regions can significantly reduce output variability and associated operating reserve requirements. In general, the aggregate uncertainty should also be mitigated by such aggregation, but the uncertainty and impacts from rare events may require more consideration. Additionally, large system or market size and system flexibility improves the operator's ability to deal with variability.
- Methods for clear and efficient prioritization of renewable resources during curtailment conditions are important for both reliability and economics. For example, regional markets should evaluate adding negative curtailment pricing to their dispatch algorithms to encourage logical and efficient responses from all resources.
- Variable generation power forecasts in multiple time frames are critical for both maintaining system reliability and economic operation. At any given point in time, the value of the forecast will depend on the operating state of the bulk power system.
- The accurate forecasting of ramp events potentially represents a significant challenge for power system reliability with respect to the integration of variable generation, although because the variability remains even when uncertainty is reduced, work toward improved forecasting must also be balanced with improvements in system operations and flexibility.
- Electrical (power, availability, curtailment) and meteorological data from wind and solar plants, delivered to the forecaster and system operator on a timely and reliable basis, are critical for forecast accuracy.

- Impact of securing ancillary services through larger balancing areas or participation in wider-area balancing management on bulk power system reliability must be investigated.

Operating Criteria and Ancillary Services

A key characteristic of wind power is its longer-term ramping attribute, which can be much different than its variability in the shorter term. One challenge is to deliver ramping capability and ancillary services from inside and outside a balancing area to equalize supply and demand. In the short-term variability, there is considerable diversity in the output from wind turbines within a single wind plant, and an even larger diversity among wind plants dispersed over a wider geographic area. Such spatial variation in wind speed makes the combined output from many turbines significantly less variable than that of a single turbine. In fact, the aggregate energy output from wind plants spread over a reasonably large area tends to remain relatively constant on a minute-to-minute time frame, with changes in output tending to occur gradually over an hour or more. These longer term changes are associated with wind ramping characteristics, which can present operating challenges.

Large wind events are similar to conventional generation contingencies in that they are big, relatively infrequent and can impact the reliability of the bulk power system reliability. They differ from conventional generation contingencies in that large wind events are comparatively slow and wind-energy output forecasting can provide system operators with some warning, enabling them to make preparations and take actions.

When wind plant output declines, other generation must increase or the load must decline. Load decline could come from the natural daily load cycle. Demand Response or an increase in conventional generation must come from the energy dispatch or ancillary service providers. If there is enough depth in the sub-hourly and hourly energy availability, there would be sufficient flexibility to maintain reliability; the energy dispatch can function normally to balance generation and load. If sufficient response is not available from the energy dispatch, use of ancillary service reserves could be deployed, although this practice is not yet accepted in many areas. In any event, if insufficient reserves are available, then re-dispatch should occur to maintain bulk power system reliability.

The slower response speed of a wind event means that the reserve service would not need to be as responsive as traditional contingency reserves, which rely heavily on the frequency response and ready-to-deploy status from spinning reserves to quickly rebalance the system. Operating reserves for a wind event can likely be brought on line in minutes and in layers to respond to reduced variable generation output. Other ways to provide operating reserve without increasing the spinning reserve requirement come from a variety of resources or demand response (*e.g.,* Demand Response, energy transactions, fast start combustion turbines, and engine-driven plants). Whether such a service should be provided as an ancillary service or via real-time energy dispatch, is a reflection of risk tolerances around the depth of supply and the availability of alternative forms available to the Balancing Authority. The more certain the supply or the availability of alternative controls, the less need for a separate defined ancillary service.

Given the relatively slow ramp of wind output events compared with loss of large dispatchable resources, it may seldom become necessary to deploy contingency reserves due to loss of wind generation. However, there are operating conditions such as tripping of wind plants at their point of interconnection that closely compare to the loss of conventional resources. In such circumstances, there should be little controversy if the Balancing Authority operator deploys contingency reserves.

Impacts on operating reserve margins and ancillary service requirements may affect short-term operational planning. It is difficult to foresee when variable generation will be available and thus will be difficult to plan an integration method. Because both the availability of variable generation energy sources and demand for electricity are often weather dependent, there can be consistent correlations between system demand levels and variable generation output. By way of example, wind power is currently the most abundant variable resource in terms of capacity. In some cases, peak availability of wind power, can often occur during periods of relatively low customer demand for electricity. This illustrates the challenge to integrate variable generation into the power grid because, in addition to off-peak production of electricity, the fuel cannot be stored for later use by consumers on a large scale.

Finally, if the bulk power system is in distressed condition, for example through a declared Energy Emergency Alert, and loss of wind output worsens those conditions, it should not be objectionable to deploy contingency reserves in order to maintain reliability. However, various markets and regional contingency reserve sharing groups have business practices and rules regarding deployment of reserves in response to wind variability.

Operating Practices, Procedures, and Tools

Improved operating practices, procedures and tools are critical to integrate variable generation into the power system, as well as improve the overall control performance and reliability characteristics of the power system.

There are significant differences in the actual scope and implementation of the individual operator tools, which can be mainly attributed to the differences in the systems and associated markets for which the tools were developed. Some of the tools are intended to provide comprehensive information about existing system operating conditions and expected short-term changes, so that the operator can decide the most appropriate control action. These operator tools include additional visualization displays and calculation of system performance metrics for determining what measures should be undertaken to mitigate possible adverse effects.

An increase in variable generation resources may require changes to the dispatch as well as the types and amounts of operating reserves to compensate for the variability and uncertainty of the new resources. In Ontario, Canada, plans to make dispatch changes have already been made. Ontario successfully adopted 11 principles that can be grouped into three categories: forecasting, visibility and dispatch. Network enhancements, and in particular improved visualization and monitoring, will enable operators to observe the stability impacts to the bulk power system at very high levels of detail. Advanced operator tools can allow operators to optimize individual generators, and groups of generators, to improve grid stability.

Additional improvements are needed in energy management system (EMS) tools to incorporate weather and wind forecasts as well as locational dispatch for system stability to compensate for the different performance characteristics of the new resources. System operators should devise systematic approaches to re-assessing the performance of the grid following the integration of intermittent renewable energy sources. They need to identify non-compliance with standards and evaluate the performance gaps between what is needed in the system and what is currently being provided for. A notable challenge for system operators is that some variable resources may be added to the system before the necessary changes can be made to assessment tools.

Some of the tools are intended to provide comprehensive information about existing system operating conditions and expected short-term changes, so that the operator can decide the most appropriate control action. These operator tools include additional visualization displays and system performance metrics for determining what measures should be undertaken to mitigate possible effects.

Communication and Coordination

Adequate communication of data and dispatch instructions is not only a reliability requirement, but a necessary tool required when integrating large amounts of variable generation. Improved forecasting accuracy and expanded back-up generation facilities (*i.e.,* natural gas plants) with expedient ramp rates can help to alleviate these disadvantages. However, in order for wind generation to provide power plant control capabilities, it must be visible to the system operator (*i.e.*, Balancing Authority) and able to respond to dispatch instructions during normal and emergency conditions.

Accordingly, enhanced communication protocols will be needed to ensure wind resources can continue to become a more significant part of the North American generation mix, without compromising grid reliability.

Real-time communication capabilities for system operators will continue to play in instrumental role, especially during system restoration efforts that require increased coordination between a given Balancing Area and the Transmission System Operator (TSO). The TSO's inability to access up-to-date information on the output of variable generation resources have caused consequences such as those seen during an event in November 2006, when the European grid experienced power disruption to over 15 million customers.[91] It was determined that grid operators lacked the capability to communicate output data for variable wind resources – most of which were reconnecting to the distribution system automatically (as system conditions allowed). The lack of real-time visibility of these resources ultimately counteracted the TSO's efforts to effectively balance the system.

Communication protocols used by wind plants and other variable generation can range from basic telephone calls and emails to different SCADA (supervisory control and data acquisition) systems. Currently, no industry-wide protocols have been established.

[91] Union for the Co-ordination of Transmission of Electricity, Final Report – System Disturbance, November 2007.

Across the North American bulk power system, each control area has established its own protocols and procedures to enhance its communication and coordination with wind plants. In particular, certain areas have made greater strides in achieving a level of communication that is required in order to contribute to the reliability of the individual system. For example, in ERCOT, real-time telemetry data, operational voice communications and other necessary exchanges are established through communication protocols which are used hourly, to ensure balanced generation and load. Additionally, meteorological data is primarily used for wind power forecasting purposes.

In many areas already observing high-levels of variable generation, protocols to share necessary real-time telemetry data may include, but are not limited to:

- Net and Gross MW and MVAR output
- Meteorological data (wind speed and direction, temperature, and barometric pressure)
- High and Low Sustained Limit (HSL and LSL)
- Normal and emergency ramp rate capabilities
- Resource status and turbine availability

Coordinating curtailment instruction must also be considered in designing communication protocols. These instructions are used primarily to reduce wind plant output during periods when the system has excess energy conditions and cannot accept the energy. Other reasons are to address system constraints (*e.g.,* line overload, shifting power flow for line reclosing, etc.) to reduce and smooth wind production when variability causes frequency control issues, and to reduce variable production during system restorations.

Follow on Actions and Recommendations

- NERC's Integration of Variable Generation Task Force is currently addressing issues relating to variable generation operational challenges.[92]
- NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing Standard development processes that have been identified by the Integration of Variable Generation Task Force:
    - Forecasting[93]
    - Operating Criteria and Ancillary Services[94]
    - Operating Practices, Procedures, and Tool[95]

[92] This Task was identified in the 2009 NERC Special Report: Accommodating High Levels of Variable Generation: http://www.nerc.com /files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf.

[93] http://www.nerc.com/files/Varialbe%20Generationn%20Power%20Forecasting%20for%20Operations.pdf.

[94] http://www.nerc.com/files/IVGTF2-3.pdf.

[95] http://www.nerc.com/files/IVGTF2-4.pdf.

Critical Infrastructure Protection

Both physical and cyber security issues must be well understood, identified, and mitigated to ensure continuous reliability of the bulk power system.

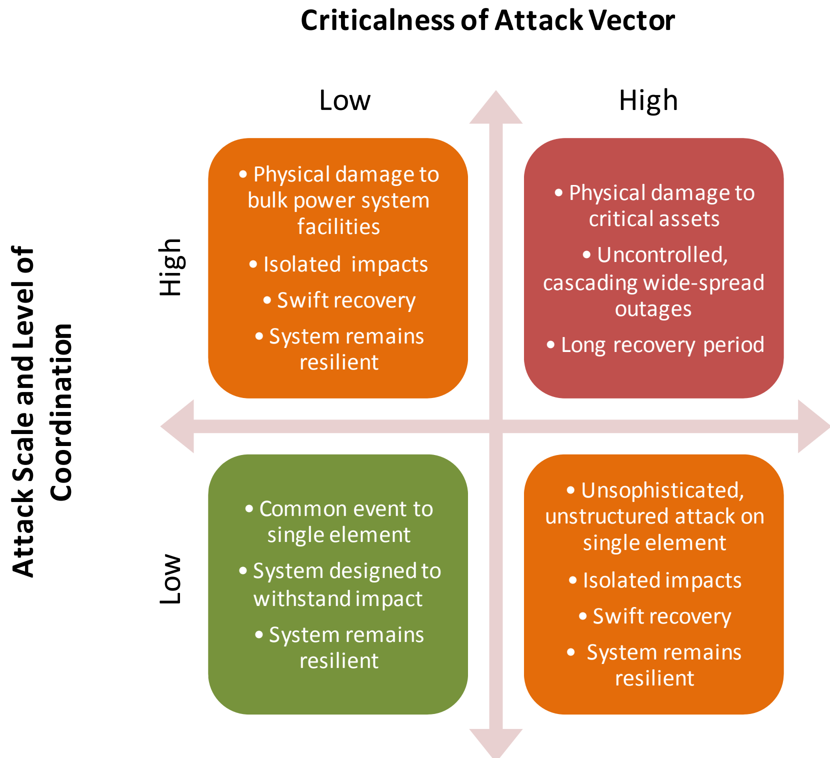
Issue Assignment

- NERC Critical Infrastructure Protection Committee[96]

Risk Assessment

- Low-Likelihood, High-Consequence in the 1 to 5 year timeframe and High-Likelihood, High Consequence in the 6 to 10-year timeframe
- Risk is primarily dependent on how critical the attack vector is and the scale and level of coordination of the attack (Figure 46)

Figure 46: Critical Infrastructure Protection Risk Matrix



Background

North America's electricity infrastructure is one of our society's most important assets. As reliance on digital technology has increased, many North Americans have come to depend on the reliable delivery of electricity to their homes and businesses to power nearly every aspect of their lives.

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96 NERC Critical Infrastructure Protection Committee: http://www.nerc.com/page.php?cid=1|9|117|139.

The challenges to adequately protect the electricity system are many. The electricity infrastructure is spread geographically across the continent, in densely populated urban areas as well as lightly populated rural areas. Generating stations, substations, and the transmission and distribution lines that connect them are a familiar and accessible part of our surroundings. While it is not possible to protect everything with absolute assurance, the electric industry is committed to develop and implement solutions that address these risks in a responsible, realistic, and effective manner.

NERC supports an “all-hazards,” “all-threats” approach to risk management, consistent with industry practices commonly used across the sub-sector. These threats and hazards can be grouped into three categories; natural, human-caused, and technological. The electricity sub-sector consistently demonstrates the ability to successfully manage many of these risks through effective business continuity planning and reliable operations, even during emergency situations.

However, certain severe-impact risks are more challenging to fully understand and address for a number of reasons, including:

- Little information is available regarding the specific nature of the risk, making it difficult to decide which preventive or mitigating actions are necessary or appropriate.
- The likelihood of occurrence is extremely low and is therefore unknown.
- The costs and resources required to comprehensively address the risk may be enormous.
- The events being prepared for may never occur.
- Risks related to national security are considered to be the responsibility of government.

Both physical and cyber security issues must be well understood, identified, and mitigated to ensure continuous reliability of the bulk power system. There is significant knowledge of the mean time between failures for mechanical devices. Knowledge of the patterns of outages caused by weather can almost be predicted. The occurrences of the substation vandal, the unforeseen trip of a generator, or many other actions can been managed due to the way the system is either designed or operated. Cyber security presents a unique risk to the reliability of the bulk power system. The crosscutting nature of technology development and deployment across the electric sector makes this issue key to the entire system, from “smart” meter to generator.

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

Additionally, NERC is also already focusing on a class of rare risks with the potential to cause long-term, catastrophic damage to the bulk power system. High-Impact, Low-Frequency (HILF) events,[97] such as, coordinated cyber, physical, or blended attack and extreme solar weather, have the potential to greatly

[97] For more information and background on these events, please see the report issues in April 2010 from NERC and the US Department of Energy titled: High Impact, Low Frequency Event Risk to the Bulk power system: http://www.nerc.com/files/hilf.pdf.

impact the critical infrastructure the industry relies upon to ensure reliable operation. While some of these events have never occurred and the probability of future occurrence and impact is difficult to measure, government and industry are working to evaluate and, where necessary, enhance current planning and operating practices to address these risks in a systematic and comprehensive fashion.[98]

There is also a risk from the integration of smart grid devices and other new and emerging technologies reliant on communications to control operations of the device. Increasing reliance on automated devices and technologies to promote reliability can increase attack vectors—which may or may not be with malicious intent. Critical Infrastructure Protection (CIP) needs to develop beyond regional standardization to a continental and trans-continental view; additionally, regional reliability problems can turn into interconnection wide problems if left uncorrected. Replacing assets after a serious cyber or physical attack and/or regional natural disasters can be challenging, as these critical assets may have long lead times for production.

There is considerable understanding of the risks associated with the generation, transmission and use of electricity. When devices fail, adverse weather moves through, or unforeseen events occur, electric grid operators respond to preposition the system and compensate for the event. Further study is ongoing at NERC to determine the impacts and losses from a large coordinated physical and cyber-attack, as well the impacts from a strong geo-magnetic storm, and the implications to restoration and asset availability.

NERC's Technical Committee's (Operating, Planning, and Critical Infrastructure) with direction from the Electricity Sub Sector Coordinating Council (ESCC)[99] have begun to address the implications to reliability through five, high profile Task Forces staffed by not only industry experts, but also supported US and Canadian Governmental agencies, scientists, and subject matter experts that are globally renowned. Their primary oversight committees are shown in (Table 30).

Table 30: High Impact, Low Frequency Event Risk Task Force

HILF Task Force	NERC Technical Committee Lead
Cyber Attack Task Force	Critical Infrastructure Protection Committee
Geomagnetic Disturbance Task Force	Planning Committee
Spare Equipment Data Task Force	Planning Committee
Severe Impact Restoration Task Force	Operating Committee
Smart Grid Cyber Security Task Force	Planning Committee

[98] See the Electricity Subsector Coordination Council's Critical Infrastructure Protection Strategic Roadmap at http://www.nerc.com/docs/escc/ESCC_Critical_Infrastructure_Strategic_Roadmap.pdf, and the Technical Committee's Coordinated Joint Action plan: http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf.

[99] The Electricity Sub Sector Coordinating Council Homepage is located at http://www.nerc.com/filez/escc.html.

These task forces are following the NERC Board of Trustees approved Critical Infrastructure Strategic Coordinated Action Plan[100] which is managed through the Joint Steering Group of NERC's Technical Committees.

Follow on Actions and Recommendations

- NERC should continue to follow the roadmap established in the Critical Infrastructure Strategic Coordinated Action Plan and provide timely updates to the NERC Board of Trustees, the NERC Members Representatives Committee, the Electric Sub Sector Coordinating Council, and NERC's Technical Committee members to ensure completion of the highest priority actions are widely disseminated to industry representatives.
- NERC Stakeholders should be engaged in the development of the next version of NERC CIP standards that is currently underway in Standards Project 2008-06 – Cyber Security – Order 706.[101]

[100] *The Critical Infrastructure Coordinated Action Plan and Strategic Roadmap* was approved by the NERC Board of Trustees in November 2010. http://www.nerc.com/filez/ciscap.html.

[101] NERC Standards Project 2008-06 Cyber Security for FERC Order 706 can be accessed at the following page: http://www.nerc.com/filez/standards/Project_2008-06_Cyber_Security.html.

Integration of Variable Generation (Planning Perspective)

Development of new planning methods and techniques that consider the characteristics of variable generation resources are required to ensure the reliability of the bulk power system.

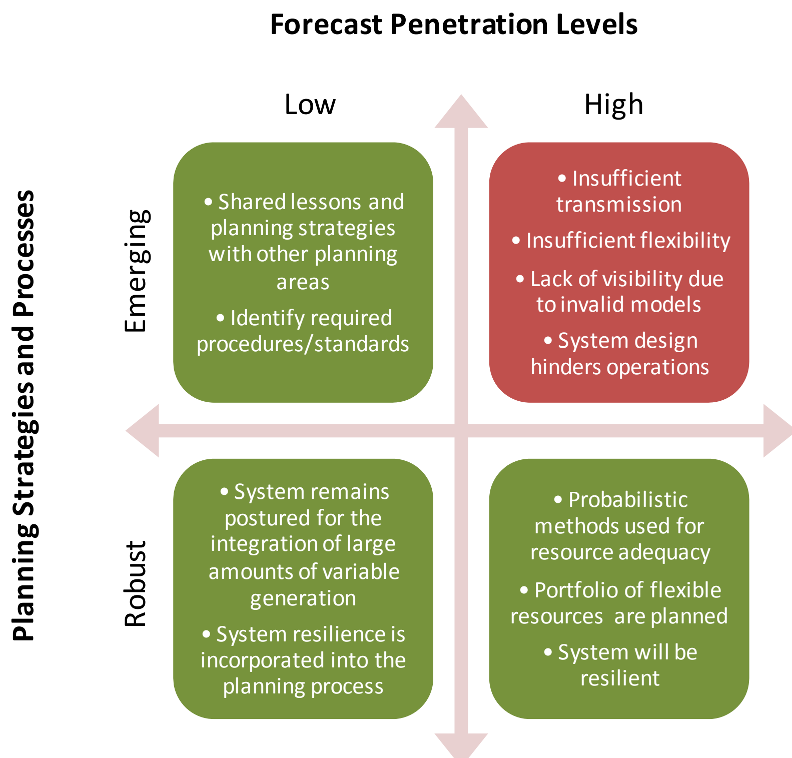
Issue Assignment

- NERC Planning Committee – Integration of Variable Generation Task Force

Risk Assessment

- Low-Likelihood, Low-Consequence in the 1 to 5 year timeframe and High-Likelihood, Low-Consequence in the 6 to 10-year timeframe
- Risk is primarily dependent on the forecast penetration levels of variable generation and the planning strategies and processes for integrating those resources

Figure 47: Integration of Variable Generation (Planning Perspective) Risk Matrix



Background

Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term bulk power system reliability. Power system planning is intended to ensure that a reliable and robust power system is available to the power system operator within the planning horizon. The industry has already begun development of new planning methods and techniques that consider the characteristics of variable generation assets to improve system reliability. However, it is the view of the NERC Planning Committee members that these tools need to be expedited to ensure the reliable operation of the bulk power system. New models need to take into account new technologies, such as storage, variable demand such as Demand Response, and incorporation of flexible resources. For example, storage technologies, if properly planned and implemented can provide the flexibility to accommodate large amounts of variable resources without the construction of additional flexible generation resources or transmission.

Power system planners are already familiar with designing a system which can be operated reliably while containing a certain amount of variability and uncertainty, particularly as it relates to system demand and, to a lesser extent, to conventional generation. However, large-scale integration of variable generation can significantly alter familiar system conditions due to increased supply variability and uncertainty. This presents new challenges to power system operators, and planners will need to design a system that can accommodate variable generation in large quantities, providing operators with the resources needed. Regional differences will exist; however, this is largely an interconnection-wide issue as policy and mandates requiring energy from renewable generation expand.

Resource Adequacy Planning

The addition of significant amounts of variable generation to the bulk system changes the way that transmission and resource planners must develop their future systems to maintain reliability. In a majority of areas, current planning approaches are based on on-peak capacity. These planning approaches are based on the study of a set of well-understood contingency scenarios, which may not encompass the latest technologies or operating strategies. Probabilistic assessment ascertains Reserve Margins needed to support reliability. With the addition of variable resources, risk assessment and probabilistic techniques based on energy limitations will be required to design and plan the bulk power system, which is a large departure from current planning strategies, except in those areas accustomed to energy limited resources, such as hydro-electric generation.

Systems planners require consistent and accurate methods to calculate capacity contribution attributable to variable generation to ensure the stability of the bulk power grid. Long-term historical data sets allow for characterization and trending of key performance metrics, including those factors that contribute to resource availability and adequacy. Variable generation, like wind and solar, does not have long-term historical data sets, and this lack of data limits the understanding of the long-term implications of variable generation performance. The potential output levels of variable generation show a large degree of variance over a vast geographic scale; therefore, the ideal type and capacity contribution of variable generation will differ by region.

The traditional approach is based on the Loss of Load Expectancy (LOLE) of 0.1 days/year as the reliability target. This approach considers only the peak hour of the days that have significant Loss of Load Probability (LOLP). This is typically a relatively small number of days because most of the year there is a surplus of capacity. A significant daily LOLE means that during the day there is some probability of insufficient generation, but the metric does not indicate the duration of the potential insufficiency, nor does it indicate the potential energy shortfall. A Loss of Load Hours (LOLH) metric considers all hours during which there may be a risk of insufficient generation. With high penetrations of variable generation, this may be an advantageous metric because of the variability of these resources. This provides a more accurate assessment of adequacy in the sense that all hours are examined by the metric. However, unlike the daily LOLE, there is no generally-accepted hourly target. While these probabilistic methods are recommended for all areas, additional analysis is required to determine the relationship between LOLE and LOLH reliability targets.

Flexibility

As the penetration of variable generation increases, system flexibility requirements will also increase. This flexibility manifests itself in terms of the need for dispatchable resources to meet increased ramping and load following some of which could occur rather unexpectedly. This flexibility will need to be accounted for in system planning studies to ensure system reliability. Enhancements to existing system planning practices will be required to account for increased flexibility necessitated by the integration of variable generation. System planning studies focus both on the reliability of the power system as well as optimizing the overall economics of the power system, here the emphasis is on reliability.

In many instances, designing systems to accommodate large penetration levels of variable generation will introduce the need to develop sources of flexibility needed to maintain reliability and improve operational efficiency. Although system operators can attempt to derive sufficient system flexibility from existing conventional resources, the physical constraints of the existing resource portfolio and/or the resulting cost may be challenging. Therefore, a broader mix of resources with flexible characteristics including storage technologies along with sufficient transmission may be needed by operators to manage the higher levels of variability and uncertainty.

In addition, institutional and/or structural changes to markets and system operations can be undertaken to facilitate the power system's ability to respond to increased variability through more flexible use of existing resources. As an example, in the presence of a large instantaneous penetration of wind resources, the differences between actual generator demand for gas supply on the pipeline system and the anticipated day-ahead nomination schedule may become divergent, potentially stressing the gas supply and transportation system. This could potentially affect the flexibility of generation whose sole source of fuel is natural gas.

The existing system flexibility varies regionally according to the different supply/generation mixes. Further, the adequacy of the regional and interregional transmission system can greatly impact the overall flexibility of the system by either facilitating or constraining the sharing of flexible resources across a broader footprint.

Transmission

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

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

In order to ensure reliability, transmission is needed to achieve the following:

- Interconnect variable energy resources planned in remote regions
- Smooth the variable generation output across a broad geographical region and resource portfolio
- Deliver ramping capability and ancillary services from inside and outside a balancing area to equalize supply and demand

Transmission system expansion is vital to unlock the capacity available from variable generation. In those regions with a competitive generation marketplace, regulatory targets such as Renewable Portfolio Standards heavily influence the location and timing of renewable generation investments and their development. Furthermore, government policy and any associated cost allocations (*i.e.,* who pays for transmission, additional ancillary services and ramping capability) will be a key driver for variable generation capacity expansion. Therefore, an iterative approach between transmission and generating resource planning is required to cost-effectively and reliably integrate all resources.

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

Currently, high-voltage transmission overlay expansions are being considered in various parts of the NERC footprint. High-Voltage Alternating Current (HVAC), High-Voltage Direct Current (HVDC) transmission or a hybrid combination of both provides expansion alternatives for this overlay approach. HVAC can flexibly interconnect to the existing AC grid, including tapping by generation and load centers, as the grid evolves. However, for very long, over ground distances (wind sites are hundreds of miles away from demand centers), or for special synchronous purposes, dedicated HVDC may be a more suitable solution. In addition to long distances, offshore applications also offer technical challenges that can preclude HVAC cables. With the advent of voltage-source converter (VSC) technologies, additional HVDC benefits (*e.g.,* reactive power control voltage and frequency control) have proven useful for offshore wind plants and may be useful in other applications.

Distributed Resources

The amount of distributed energy resources (DER) present in the electrical grid is forecast to grow in the next decade. It is also recognized that many types of DER (demand response and storage, for example) may improve bulk system reliability if managed properly. In the past, the distribution system was based mainly on distributing power from the transmission network, and therefore its impact on bulk system reliability was relatively small. As Smart Grid developments increase resulting in more bi-directional flow of energy and provision of ancillary services from the distribution system, the impact on bulk system reliability needs to be understood and managed.

Distributed resources currently account for a relatively small portion of generation. However, there is already a significant amount of reciprocating engines connected at the distribution level, as well as micro CHP plants. These resources all have different characteristics which in large numbers may aggregately affect the bulk system. Most, if not all, are not presently visible or controllable by the bulk system operators, and many are connected according to the IEEE 1547 standard, which requires disconnection from the system for abnormal system conditions raising issues with fault ride through with high penetrations of DER. High levels of distributed variable generation connected to the system may cause particular problems due to the uncontrollable nature of its output.

The following potential bulk system reliability impacts of high levels of DER have been identified:

- Non-dispatchable ramping/variability of certain DER
- Response to faults: lack of low voltage ride through, lack of frequency ride-through and coordination with the IEEE 1547 interconnection standards for distributed generation
- Potential system protection considerations
- Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS) disconnecting generation and further reducing frequency and voltage support
- Visibility/controllability of DER
- Coordination of system restoration
- Scheduling/forecasting impacts on base load/cycling generation mix
- Reactive power and voltage control
- Impacts on forecast of apparent load seen by the transmission system

These issues may impact the bulk system at different levels of penetration, depending on the characteristics of the particular area to which the DER are connected. Some factors will need to be managed by technical requirements (grid codes) for the DER itself, while others need the bulk system operator to adapt new planning and/or operational methods. Significant amounts of DER can affect the power flow on the transmission and sub-transmission systems, which can result in thermal overloads or significant changes in profile. The uncertainties associated with the variable output (in aggregate) can create additional uncertainties in net demand to be served by transmission and balancing resources, with an added complication to the system operator of limited monitoring and control of the output from distributed resources. Certain regions, such as Hawaii or Germany, are already seeing significant challenges of the type outlined here. Studies and real world experience have shown the potential impact of significant penetrations of DER. In particular, much attention has been focused on both the impact of variability and uncertainty, which can be invisible to the bulk system operator, and low voltage or low frequency response of DER. High DER penetrations have been shown to affect the transient and small signal stability of the system – this can be either positive or negative depending on the type of DER (e.g. inverter connected DER can adversely or beneficially affect stability depending on control schemes employed).

Should DER penetration reach a sufficient market threshold, DER will impact resource management and transmission reliability, resulting in the need for more information to be provided to system and transmission operators. However, current practices in many areas do not require information to be provided from DER to the bulk system and therefore cannot be considered in either bulk planning or operations. The level of DER which will cause issues in a given operating area will vary by area and DER technology; therefore, there may not be a one-size-fits-all solution.

Standard Models

Non-proprietary and publicly available models for the simulation of steady-state (power flow), short-circuit (fault calculations) and dynamic (time-domain simulations) behavior of such generation resources must be made readily available for use by power system planners. Furthermore, these models should be routinely validated to ensure proper representation of variable generation power plants in bulk power system studies. A model is valid if its dynamic behavior is close enough to reality so that its influence on the network of interest (*i.e.,* used for power system studies) is consistent with the fidelity of model structures and available data for the power system and other generation, as it pertains to the phenomena of interest (*i.e.,* in stability studies). That is, perfect curve fitting is not necessary, but to the extent possible erroneous model dynamics must not result in a notable over-design or under-design of the network.

Follow on Actions and Recommendations

- The NERC Integrating Variable Generation Task Force should complete their work on planning requirements for integrating large amounts of variable generation.
- NERC should address recommendations for adopting probabilistic approaches for determining capacity contributions of variable generation.[102]
- NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing Standard development processes that have been identified by the Integration of Variable Generation Task Force:
    - Distributed Resources[103]
    - Standard Models[104]
- NERC should develop metrics that measure flexibility needs for variable generation.[105]

[102] http://www.nerc.com/files/IVGTF1-2.pdf.

[103] http://www.nerc.com/files/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011%20%282%29.pdf.

[104] http://www.nerc.com/files/Standards%20Models%20for%20Variable%20Generation.pdf.

[105] http://www.nerc.com/files/IVGTF_Task_1_4_Final.pdf.

System Modeling Improvement and Coordination

The improvement of interconnection-wide simulation models in the future will be necessary to support and reliability integrate a changing resource mix projected over the long-term, address interconnection-wide phenomena such as, event forensics, transient stability, frequency response and geomagnetically induced currents.

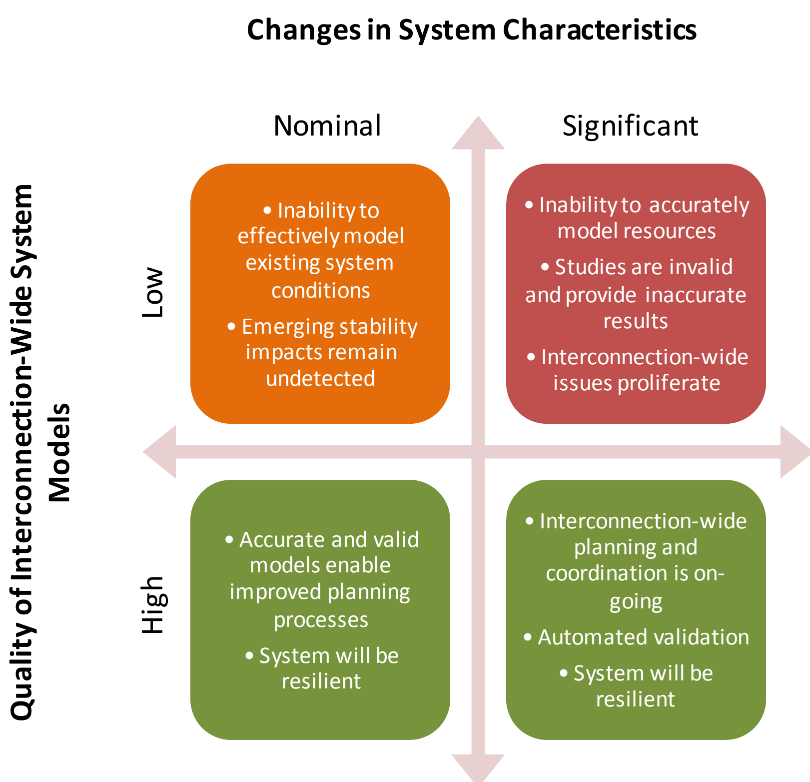
Issue Assignment

- NERC Planning Committee – System Analysis and Modeling Subcommittee
- NERC Planning Committee – Model Validation Task Force[106]

Risk Assessment

- Low-Likelihood, Low-Consequence in the 1 to 5 year and the 6 to 10-year timeframe
- Risk is primarily dependent on the on-going and future changes in system characteristics (i.e., generation-mix, demand characteristics, transmission upgrades) and the quality of the interconnection-wide system models.

Figure 48: System Modeling Improvement and Coordination Risk Matrix



[106] NERC Model Validation Task Force: http://www.nerc.com/filez/mvtf.html.

Background

The planning and operation of large interconnected power systems is a complex task which requires daily analysis and significant computer simulation modeling. System planners and operators use these simulation studies to assess the potential affect of credible (and sometimes extreme) contingency scenarios and additionally to assess the ability of the power system to withstand such events, while remaining stable (*i.e.,* avoiding cascading outages). The improvement of simulation models in the future will be necessary to support and reliability integrate the projected changing resource mix.

Non-proprietary and publicly available models for the simulation of steady-state (power flow), short-circuit (fault calculations), small signal (frequency-domain) as well as dynamic and long-term (time-domain simulations) behavior of such generation resources are needed by power system planners. Furthermore, these models should be routinely validated to ensure proper representation of variable generation power plants in power system studies. A model is valid if its characteristics and behavior is close enough to reality so that its influence on the network (*i.e.,* used for power system studies) is consistent with the fidelity of model structures and available data for the power system and other generation, as it pertains to the phenomena of interest (*i.e.,* in stability studies). That is, perfect curve fitting is not necessary, but, to the extent possible, erroneous model dynamics must not result in a notable over-design or under-design of the network.

In terms of personnel resources, many organizations may not have a sufficient number of trained staff with available time to perform these activities. This workforce shortage and the age of the existing knowledgeable workforce have been cited as a growing problem in past NERC Long-Term Reliability Assessments. Many of the activities associated with model validation require training, experience, and skill – qualities which take time to develop. Therefore, new staff and training required to support for more vigorous model validation processes should be adopted.

Reliability Impact

When a credible disturbance event is simulated in computer models of the power system and the result is unacceptable performance, system planners and/or operators must develop operating strategies, adjustments to existing system components or planned equipment additions (*e.g.,* line re-conductoring, addition of shunt reactive compensation devices, etc.) to address the potential problem. Validation of planning models is needed on a regular basis to ensure the model is working correctly and delivering accurate results. There will always be evolving changes in the characteristics of the power system, particularly with respect to load characteristics. Unforeseen interactions can also occur when new control strategies are used through the addition of novel devices and technologies. The models must therefore be validated periodically to ensure that trends in the power system which can affect reliability are captured in system studies.

Further, study of interconnection-wide phenomena is becoming more important, to address frequency response, inertial response, small-signal stability, extreme contingency impacts, and geomagnetic disturbances. To ensure proper system performance, validated models are required that reasonably represent actual equipment performance in simulations to confidently support planned system enhancement. All devices and equipment attached to the electric grid must be modeled to accurately capture how that equipment performs under static and system disturbance conditions. Models provided for equipment must be open-source and shareable across the interconnection to support reliability of the interconnection. Such models cannot be considered proprietary.

Periodic model validation and benchmarking are integral to off-line study model maintenance and need to be completed regularly to keep up with ongoing changes and additions to the power system. System disturbances present unique opportunities for model verification and identification of necessary model improvements. The goal of that validation should not be to mimic just one response but rather to provide the best match of response to a number of system conditions. Steady-state power flow analysis is performed on a routine basis by system and operational planners for reliability assessment. In addition, engineers build power flow cases of future year scenarios to plan system additions to support reliability in future years, complete sensitivity analysis for scenarios, or build cases to study past disturbances.

In addition, system models should be updated and validated when significant changes to system topology are made, addition or adjustment of generators or their governor, exciters, power system stabilizers, etc., as well as system equipment that include active controls that could affect system dynamics.

Resource Adequacy Considerations

Accurate and validated models are essential to resource planning. Models need to be improved in multiple ways, one of which is developing open source models for the entire spectrum of supply resources (hydro, steam, gas, geothermal generation) along with rapidly emerging wind and solar plants.

Transmission Adequacy Impacts

For transmission lines, transformers, and shunt capacitors/reactors, model development is accomplished by an accurate calculation of the impedances, ratings, and other parameters that are incorporated into the full steady-state network model. In modeling a large power system, such as the Western or Eastern Interconnection in North America, there are several categories of models that need to be developed. For example, one category of modes is for the representation of the transmission system. This includes transmission lines, power transformers, mechanically switched shut capacitors and reactors, phase-shifting transformers, static VAR compensators (SVC), flexible AC transmission systems (FACTS), and high-voltage dc (HVDC) transmission systems. The models often include equipment controls such as voltage pick-up and drop-out levels for shunt reactive devices.

Model refinement during the validation process for individual components, to some extent, can be automated. Power flow component models can be validated by direct measurement. For example, transmission line parameters (resistance, reactance, and capacitance) are verified by using measured voltage, real power, and reactive power flows from each end of the line. However, the accuracy and precision of such measurements is limited. Dynamic model parameters can be selected such that the simulated model response provides a best fit to a measured response according to a suitable error criterion.

Operations Impacts

Improper or incorrect models can result bulk power system reliability impacts and, ultimately, serious reliability conditions or widespread power outages, as in the summer of 1996 in the Western Interconnection. Therefore, realistic models are needed for ensuring reliable and economic power system operation.

Follow on Actions and Recommendations

- NERC and Regional Entity staff have made improvement of interconnection-wide models, with this enhancement as a top priority item for 2011 through 2013 time horizon.
- The Model Validation Task Force, reporting to the Planning Committee is developing recommendations for enhanced model validation.
- NERC is leading the effort through Regional Entity staff to engage the model development groups of each Interconnection (ERAG,[107] ERCOT, and WECC), and build plans for their improvement, based on priority interconnection-wide study requirements. NERC staff's goal is to not to direct the development of each interconnection's model, but to provide guidance and feedback to the modelers, as all stakeholders have a vested interest in developing the most accurate interconnection model possible.

[107] ERAG is the Eastern Interconnection Reliability Assessment Group and contains representatives from the following NERC Regions: FRCC, MRO, NPCC, RFC, SERC, and SPP.

Increased Gas Generation to Support Variable Generation

With increasing variable generating resources coming on-line, low capacity-factor gas turbine plants may be required to manage increased system variability to meet reliability requirements.

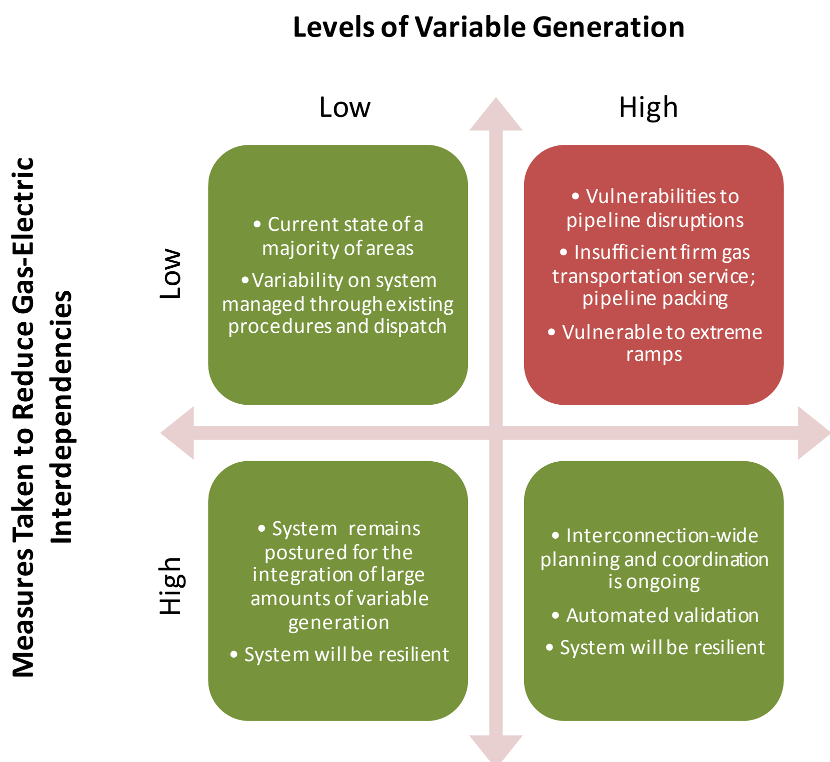
Issue Assignment

- NERC Planning Committee – Integration of Variable Generation Task Force
- NERC Planning Committee – Reliability Assessment Subcommittee

Risk Assessment

- Low-Likelihood, Low-Consequence in the 1 to 5 year and High-Likelihood, Low-Consequence in the 6 to 10-year timeframe
- Risk is primarily dependent on the on-going and future changes in system characteristics (i.e., generation-mix, demand characteristics, transmission upgrades) and the quality of the interconnection-wide system models (Figure 49)

Figure 49: Increased Gas Generation to Support Variable Generation Risk Matrix



Background

Using gas-fired generation to balance the variable output profile for wind generation is relatively new to the industry.[108] Wind generation has increased dramatically since about 2005, particularly in the west,

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108 For most electric utilities gas-fired generation is considered the best alternative for balancing, or backing up, the variability in wind generation. For a few electric utilities hydro generation represents the best alternative.

Midwest, and Texas. The majority of new North American generating installed capacity projected for the next 10-years will be fueled by natural gas and wind. With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation the choice for new generating capacity in the future. As the bulk power system has been developed to support the delivery of energy from the existing generating fleet, sufficient time will be required to both site new gas-fired generation and reinforce the bulk power system.

Meanwhile, resource adequacy and transmission planning approaches must consider needed flexibility to accommodate the characteristics of variable resources as part of bulk power system design. With the addition of large amounts of variable generation (*e.g.,* wind and solar), low capacity-factor[109] gas turbine plants may be required to manage increased system variability to meet reliability requirements. Further, sufficient fuel will be required not only to provide daily energy requirements, but also support the need for ancillary services vital to support variable generation integration, as well as for normal operational requirements. A significant operating concern in using low-capacity factor gas turbine generators is the impact from material fatigue (caused by units cycling up and down) which can ultimately result in higher maintenance and potential effects on their forced outage rates.

On an interconnection-wide or Balancing Authority-wide basis, the increased use of gas-fired generation to support base-load capacity requirements for reliability will impact the availability of these units to support variable generation assets. Viewing the issue through a more regionally focused perspective, impacts could include generation/transmission adequacy, requisite flexibility of generating resources, and challenges to real-time operations. As variable generation provides less certain capacity, sufficient capacity will be needed to support adequacy. Additionally, sufficient ancillary services (and fuel for this capacity) will need to be developed to ensure reliable operation of this service.

Reliability Impact

The basic measures of a plant's flexibility are: its ramp rate, measured in megawatts-per-minute or some other short time period; its minimum generation level; and its total capacity. Minimum generation is most often defined by a combination of physical limits and economic limits, as when a plant's efficiency drops off dramatically below a certain point. Power system operators need to set aside a certain amount of flexible generation that is load following to maintain a reliable grid. More flexibility in generation resources is required if there is a significant amount of wind or other variable generation on the system. As variable generation provides less certain capacity, sufficient flexible capacity will be needed to support adequacy.

Continued high levels of dependence on natural gas for electricity generation persist in areas such as Florida, Texas, the Northeast, and Southern California. Additionally, more gas-fired generation is expected over the next 10-years, providing the greatest amount of future on-peak generation. Efforts to address this dependence must be continued and actively expanded to avoid risks to future resource adequacy.

[109] The capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time.

Operations Impacts

Since the timing of when the wind will blow is dependent upon weather events and somewhat normal diurnal patterns, the actual period of wind generation can be very difficult to predict. Similarly, it is equally difficult to predict the period when the wind will not blow, which is when additional gas-fired generation is required to fill-in, or balance, the electric utility's load profile. Gas turbines are almost an ideal technology to compensate for wind power variability. They can be quickly started (some open-cycle gas turbines have cold startup times of less than 5 minutes) and can ramp up and ramp down their power levels faster than coal, steam, and nuclear plants can. This creates a new dimension to the swing nature of electric gas loads and can be a significant phenomenon is areas where wind generation is concentrated heavily (*e.g.,* Texas and North Dakota).

The strong growth in wind power and the lack of cost-effective electric storage solutions means systems will rely heavily on gas turbines to compensate wind power variability. Even in regions with significant amounts of hydropower (another flexible and responsive technology to compensate for wind power variability), gas turbines may still be needed to backup wind power because environmental regulations limit the minimum and maximum amount of water a hydroelectric dam can release (termed run-of-river constraints).[110] In Quebéc, however, large multi-annual reservoirs are perfectly suitable for this compensation without the use of gas. Entities in the Quebéc Interconnection have put systems and contracts in place to leverage the storage and fast ramping capabilities of its hydro resources to complement wind power variability.

Gas turbines operate best at full-power steady state conditions where they are at their highest fuel and emissions efficiencies. Deviations away from this tuned set point result in significant inefficiencies (particularly with NO_x emissions) and increased operational costs. In some cases, wind power variability reduces the amount of CO_2 emissions wind power can displace by 25 percent.[111] NO_x emissions for the majority of the cases studied were not reduced and in some instances increased substantially. This is particularly important when considering pending environmental regulations and potential carbon legislation.

However, the gas delivery infrastructure may require augmentation to include sufficient storage facilities, ancillary services and dispatch alignment. These elements will be increasingly a concern as the unprecedented shift in resources takes place over the next decade.

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[110] In recent events, Bonneville Power Administration (BPA) has called to curtail wind generation during periods of low demand due to hydroelectric generation limitations. http://205.254.135.24/todayinenergy/detail.cfm?id=1810.

[111] Katzenstein and Apt's results are for wind + gas base-load plants. In other words, the turbine whose emissions are displaced is the same turbine that provides compensating power. Reference: Katzenstein, W., Apt, J. Air Emissions Due to Wind and Solar Power. Env. Sci. Technol., 2009, 43 (2), pp 253–258.

Follow on Actions and Recommendations

- In 2011, NERC issued a Special Assessment that studies the interdependency between Natural Gas production, transportation, and its use as a generation fuel for the electric industry.[112] This report can act as a platform for continued dialog between the electric and gas industry.
- In 2012, NERC will engage industry to study contingency impacts and operational requirements to facilitate this needed dialog.
- NERC should engage with regulatory agencies, as well as gas and electric industry stakeholders, to harmonize the interaction and enhance the coordination between the industries' policies, practices, and obligations.

[112] 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States report: http://www.nerc.com/page.php?cid=4|61, December 2011

Canadian Energy Landscape

Constitutional Framework

In Canada, when discussing energy issues, in particular electricity, it is useful to start with respective jurisdictional authorities.

> *The Provinces of Canada have non-renewable natural resource ownership and development authority; there is specific reference to electricity production and generation in the Canadian Constitution Act[113] ("development, conservation and management of sites and facilities in the province for the generation and production of electrical energy").*

This gives the Canadian provinces authority to set the regime for electricity in their jurisdiction. There is a mix of retail and wholesale open markets for electricity across the country. Many major utilities remain Crown owned. Some utilities have been unbundled and others remain integrated (or have been re-integrated).

Federal energy authority is primarily over interprovincial and international trade and commerce; however the Canadian Federal government has authority of the full cycle of nuclear generation from uranium mining through waste management.

Canada's Federal energy policy, as outlined by Natural Resources Canada (NRCan), has three main components; a market orientation; respect for jurisdictional authority and the role of the provinces and; where necessary, targeted intervention in the market process to achieve specific policy objectives through regulation or other means**.** These policy objectives include issues of health and safety (*e.g.,* pipeline regulation) and environmental sustainability.

There is also some shared jurisdiction on environment issues where there is no clear separation of power. However, as a whole, Canada has a very active policy and regulatory agenda for future electricity plans in the country.

Regulatory Framework

There are eight (8) provinces which are part of the NERC/Regional Entity overseen bulk power system. Seven of these provinces have independent regulators; one contains all authorities in its Crown-owned utility. SaskPower has, subject to government policy direction, authority for planning, construction, operations, standards, and authority in matters pertaining to rate setting and oversight. Three provinces (Alberta, Ontario, and Québec) have ISOs that have a role in systems operations and planning. These ISOs also provide technical support to the Provincial government in which they operate and the Provincial regulator, if needed.

The Federal regulator of Canada, the National Energy Board (NEB), issues permits for International Power Lines (IPLs) as well as permits to export electricity. IPLs are defined by NEB to be from the last

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[113] http://laws.justice.gc.ca/eng/Const/Const_index.html.

transformer located in Canada to the border of the United States. NEB requires the applicant for an IPL to provide information on the impacts of the operation of the proposed power line on the power systems in other provinces (*i.e.,* other than those provinces through which the line passes).

As part of its regulatory mandate, the NEB monitors the Canadian supply and demand scenarios for all energy commodities including oil, natural gas, natural gas liquids and electricity. Energy Market Assessments address specific issues related to Canadian energy markets, such as the deliverability of natural gas, the outlook on oil sands production, and emerging technologies for power production. The NEB publication, Canada's Energy Future, issued in 2007 serves as a comprehensive energy supply and demand outlook for 2005 to 2030 using a reference case and several scenarios. The NEB presents energy outlooks on demand, supply, and industry trends seasonally to inform Canadians on the factors and trends impacting the summer and winter energy markets – but with a price focus unlike the NERC summer and winter adequacy assessments. A review of its website shows that the NEB has done no electricity focused studies since one on coal-fired generation in July 2008. The last full electricity market assessment on the website was done in 2005.

Planning Framework

There is no overarching national planning framework in Canada. However, there are a number of activities that go on at the national level.

The Council of Energy Ministers (CEM) composed of the Federal and provincial and territorial energy ministers meets annually. The CEM does not get to planning level, although it sometimes commissions studies, for example on the east-west transmission, and undertakes discussion of such topics. A working group also looks at electric reliability issues on an ongoing basis, and meets with FERC and other US and Mexican authorities. This is an offshoot of the Canadian group that worked with US counterparts on the principles for an international ERO that underpins the NERC model following the 2003 northeast blackout. The Federal government also coordinates Canadian participation in the clean energy dialogue with US - two specific electricity forums have been held, one on workforce challenges and the other on smart grid issues.

A number of activities also take place at the regional level including the Atlantic energy gateway discussions (intended to encourage the development of additional clean and renewable energy supplies in Atlantic Canada while actively promoting Atlantic Canadian renewable energy to new markets) and Manitoba/Ontario possible generation and transmission projects. In general, these would not be called planning activities.

The Canadian Electricity Association has perhaps the broadest Canadian perspective on electricity matters. For example, the report, titled *Building Tomorrow's Electricity System – Electricity Fundamentals for Decision Makers*[114] report was published in 2009 and intended primarily for policy makers, providing industry considerations from both a provincial and federal perspective.

[114] http://www.electricity.ca/media/1490-CEAguide_v3selected_v2_WEB_decision_maker.pdf.

To a great extent planning is up to the provinces with most planning at the provincial level involving a number of players. The government generally sets the direction through policy and/or legislative directions. For example, Ontario's Green Energy Act with emphasis on smart grid implementation and renewable energy incentives, Nova Scotia's mandating the proportion of generation required to be from renewable energy and British Columbia legislating the requirement for electricity self-sufficiency in the province by 2016 (among other elements). Utilities or other players tend to do the detailed technical planning, and, in most jurisdictions, regulators have a role in project approvals, including final siting and rate determinations that govern actual systems construction. They usually also review long-term capital plans from utilities. There are a number of models for regulation, planning and operations. Below is a sample of jurisdictional differences in Canada provided as representations of ongoing legislative, regulatory and industry activities.

In Ontario, there are the following responsibilities for electricity in the province:

- **Regulation**: The Ministry of Energy has over-all responsibility for setting policy direction and for regulating the energy market. The Ontario Energy Board (OEB) is responsible for regulating the electricity and natural gas sectors
- **Planning and Operation**: The OPA is responsible for ensuring a reliable and sustainable supply of electricity for Ontario planning the power system for the long-term and ensuring the development of needed generation resources. The Independent Electricity System Operator (IESO) manages the day-to-day reliability of operations and produces short- and mid-term reliability studies
- **Generation, transmission and distribution**: Ontario Power Generation (OPG) and private companies produce electricity using a variety of fuel sources. Transmitters, particularly Hydro One, move power across long distances to where it is needed and more than 80 distributors (including Hydro One) delivery electricity to homes and businesses
- **Retailers**: There are a number of retailers who delivery electricity to consumers, including First Nations and Metis communities.

Québec still follows a rather traditional model. The Provincial government is Hydro-Québec's sole shareholder. Hydro-Québec has three main divisions, Hydro-Québec Production (HQP, the Generator Owner), Hydro-Québec Distribution (HQD, Load Serving Entity) and Hydro-Québec TransÉnergie (HQT, the Transmission Owner, Planner and Reliability Coordinator). These divisions operate under rules of functional separation. A number of smaller companies operate generating stations on the system and most sell their electricity to HQD. The government (acting as sole shareholder) usually makes decisions on high level trends and orientations. These orientations may direct HQP to develop generation projects or HQD to initiate demand response or energy saving programs, among other things. HQD is also responsible for the procurement process to supply its load. HQT may initiate transmission projects to integrate resources to the grid or to enhance reliability. All HQD and HQT projects are submitted to the Québec Energy Board for approval. Additionally HQD must file a long term resource plan every three years, covering the next 10-years and including demand forecasts, resource expansion plans, and reliability assessments. The last Plan covering years 2011 through 2020 was submitted November 1st, 2010. Québec also works with NPCC and neighboring Regions on Regional issues, within different operating and planning Task Forces and working groups.

British Columbia's (BC) 2008 energy legislation contains energy objectives for BC that include electricity self-sufficiency for the province by 2016, the requirement for long-term plans by utilities, inducements to increased use of Demand Side Management (DSM), limits on carbon emissions from generation sources and requirements for proportions of generation to be from renewable and clean energy sources There was also a requirement for the British Columbia Utilities Commission (BCUC) to conduct an inquiry to make determinations with respect to BC's infrastructure and capacity needs for electricity transmission for the next 20 years, or other period specified by the 2010 legislation exempts a number of "strategic projects and programs" from separate approval by the BCUC as well as removing its jurisdiction over projects specifically for the export market.

In 2010, new energy legislation re-integrated BC Hydro (components of which were separated in 2003). It also changed the powers of the BCUC, removing its responsibility for conducting the long-term (30 year) assessment of transmission and generation needs and assigning BC Hydro the task of submitting to the government for approval an Integrated Resource Plan covering the province's electricity needs over the next 20 years. This is to be submitted within 18 months of the legislation coming into effect (December 2012 is target date). Once a plan is approved, the BCUC is required to consider and be guided by it in taking future decisions. For BC Hydro, a 20-year Base Resource Plan sets a mix of demand-reduction, generation and transmission options that are able to fulfill the forecasted demand.[115] The plan includes contingency Resource Plans that address the uncertainties inherent in long-term planning, such as higher than expected demand. Contingency resource plans will put forth a range of alternative resource options that would be relied upon if conditions change significantly. There will also be a 30-year transmission plan as part of the integrated resource plan.

In Alberta, the Alberta Electric System Operator (AESO) is responsible for long-term planning, including transmission system outlook documents with 20 and 10-year horizons. In 2009, new energy legislation gave the government the authority to declare certain transmission infrastructure projects as "critical" and eliminate the "needs" hearing with the Alberta Utilities Commission (AUC). In June 2011, the AESO published its Long-Term Transmission Plan which addresses with critical transmission infrastructure as well as issues of reliability, standards, and its ongoing work to establish a compliance monitoring program.[116] It has identified some infrastructure as critical. This is part of a concerted effort by Alberta to improve its transmission and enhance interties and includes elements of regulatory streamlining.

[115] http://www.bchydro.com/planning_regulatory/irp/development_process.html.

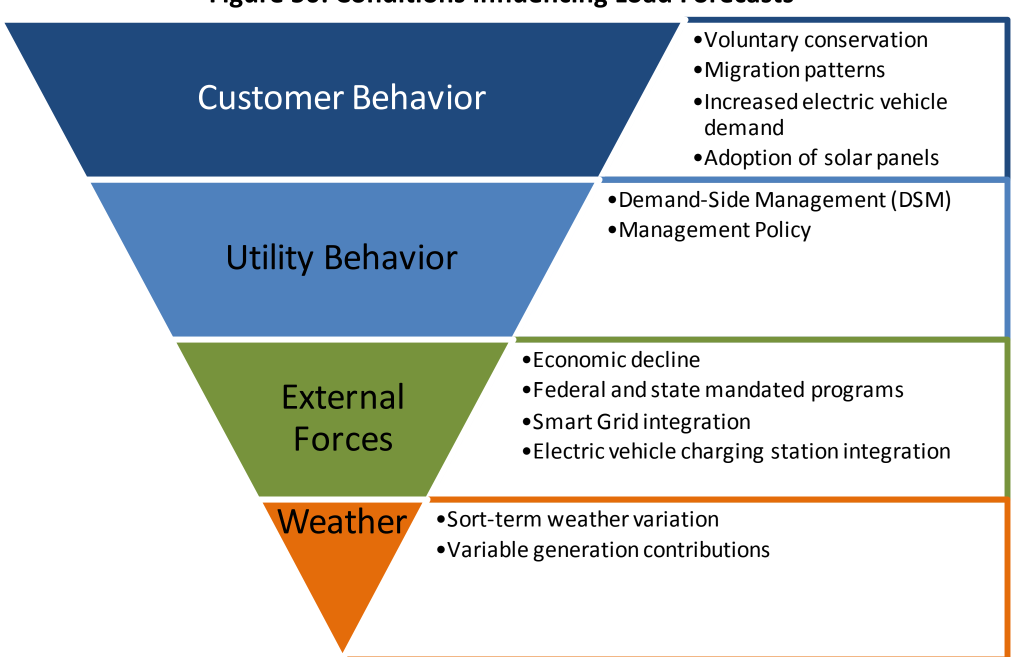
[116] http://www.aeso.ca/transmission/22021.html.

Load Forecasting Uncertainty

The electric industry is currently facing several challenges in forecasting demand for electricity. The accuracy of demand forecasts have been decreasing since the beginning of the last recession, which officially began in late 2007 and ended in mid-2009. This section addresses the potential reliability concerns created by these challenges (Figure 50):

- **Customer Behavior**: Consumer electricity use is influenced by social, economic, and commercial conditions that may increase or decrease consumer electricity demand. The overall magnitude of these impacts is currently undefined; however, new technologies, such as Advanced Metering Infrastructure (AMI), Phasor Measurement Units (PMU) and other smart grid components may alleviate some of the uncertainty in forecasting customer behavior. More importantly, as these technologies mature, it is expected that they will help utilities to improve the quality of customer load data.
- **Utility Behavior**: Utility programs such as Demand-Side Management and Energy Efficiency are creating new trends in load forecasts; however, the considerations for short- and long-term generation planning are unclear at this time.
- **External Forces**: Issues that are currently beyond the control of utilities include integrating fleets of electric hybrid vehicles (EHV), Energy Efficiency initiatives mandated by Federal and State regulators, and the accuracy of projections for economic recovery. These issues can impact the current trends in load forecasting, making long-term planning margins more unpredictable.
- **Weather**: Challenges in understanding historic weather patterns make it difficult to forecast long-term weather and its impact on customer demand, introducing a greater degree of variability in load forecasts.

Figure 50: Conditions Influencing Load Forecasts



Background

The electric generating industry faces new challenges in standard load forecasting practices as a result of the economic recession that began in late 2007. Some of these challenges have not been seen in former recessions. The most recent economic downturn has caused a significant reduction in projected long-term energy demand and presented new uncertainties in long-term forecasting in areas across North America. Historically, load forecasts tend to have a gradually increasing slope; however, trends in many regions have reversed, projecting short- and long-term declines in energy consumption.

As consumer confidence, as tracked by the Conference Board,[117] returns to pre-recession levels, load forecasting tools might not accurately reflect these changing conditions. For example, during the summer of 2010, ERCOT and SPP reported all-time peak demands.[118] In 2011, ERCOT and SPP both set another all-time peak record. These results raise additional uncertainty for demand projections in how to accurately forecast a rapidly recovering economy. This presents new challenges for the industry to redefine load forecasting practices to adequately reflect the current energy demand climate and increase the accuracy of demand projections.

The industry is faced with the challenge of analyzing actual contributions of explanatory variables, and enhancing forecasting models to generate more accurate results for short-term planning horizon. The very meaning of uncertainty, however, is the increased possibility of more disparate outcomes. In other words, uncertainty signifies less predictability that means, in turn, less accuracy. By definition, greater uncertainty and greater accuracy cannot occur jointly.

Greater uncertainty encourages reliance on other forms of contingency planning (non-forecasting) responses to address increased uncertainty. Traditionally, load uncertainty has been addressed by incorporating a Reserve Margin in all area demand forecasts. Installation of low-fixed-cost peaking capacity with higher running costs to address load uncertainty, as opposed to choosing which demand forecast should be adopted is a common method for planning systems.

Economic costs and benefits play an important role in load forecasting. Uncertainty often results in costly outcomes to industry. Wide variation in future forecast demand outcomes could lead to higher electricity costs, as utilities carry less capacity than needed and have un-served energy demand. However, the alternative presents other costs if industry may carry excess generating capacity, resulting in reduced revenue. In either scenario, with forecasts predicting higher highs or lower lows, the result equates to greater costs for utilities.

The notion of Expected Value of Perfect Information (EVPI) represents the optimal outcome of economic cost. Under conditions of increased uncertainty, EVPI also increases, thereby justifying the expense of collecting additional information. However, just the collection of additional information from customers has a cost. The limit to incurring additional information is to not exceed the expected value of having perfect information. Consequently, greater uncertainty leads to increases in the value of perfect

[117] http://www.conference-board.org/.

[118] NERC 2010 Post-Summer Reliability Assessment: http://www.nerc.com/files/2010PSRA_FINAL.pdf.

information, which in turn, justifies the increased spending on mitigation (*e.g.,* “better” forecasting, contingency planning, and new capacity with higher variable cost but lower fixed cost).

Forecast accuracy is also problematic to examine. It might appear forecast accuracy has diminished since the recession of 2007. However, this may not be correct. The main evidence for this statement appears to be the substantial reductions in projected Net Energy for Load (NEL), while several other areas were concurrently reporting all-time highs in peak demand. For a variety of reasons, actual peak may bear no resemblance to projected peak. A legitimate comparison of actual versus projected peak requires the use of temperature and Demand-Side Management adjustments. In some cases, such “normalized” peaks are not generally reported publically, and are sometimes misused (even within utilities), since not all parties are necessarily privy to the information. Without a proper comparison of recent actual versus projected peak demand, the accuracy of the peak forecast is indeterminate.

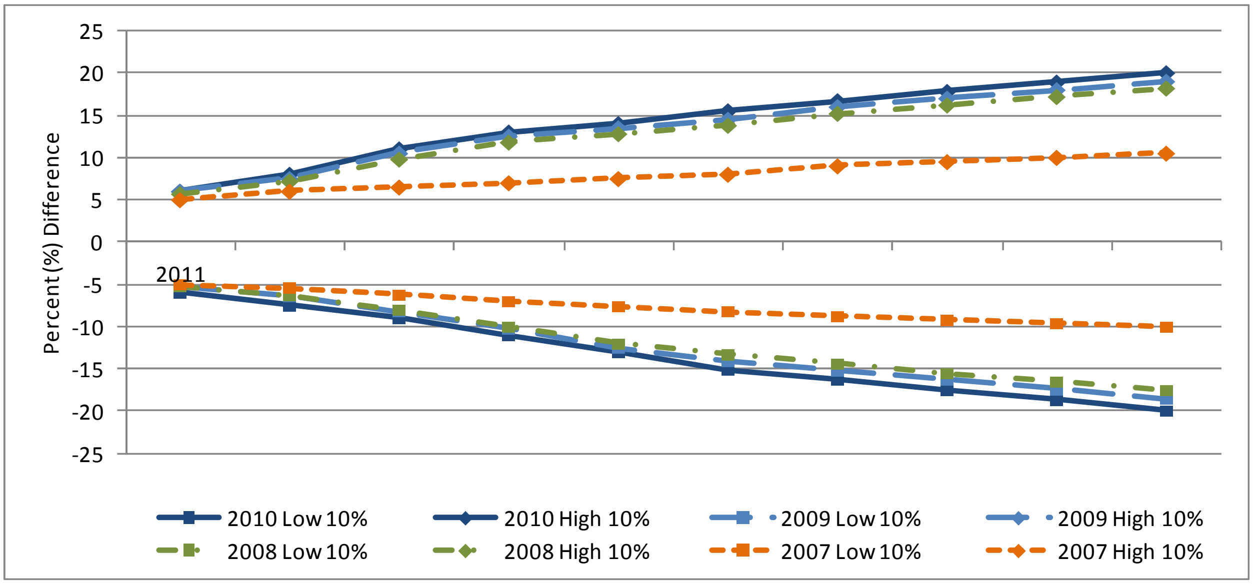
A precision forecast of the exact level and turning point of near-term activity requires three things:

- an accurate forecast of all values of future exogenous variables (outside-the-system variables like fiscal policy),
- an accurate description of the dynamic (time delay) properties among the endogenous variables (variables determined within-the-system), and
- an accurate model of all interactions among the variables determining the behavior of the system.

Such precision is not feasible for open large-scale systems like economies or utility service areas. For these reasons, most short-term forecasts address uncertainty by use of scenario analysis instead of precision models.

The high and low summer demand 80/20 bandwidths for 2007-2010 are shown below (Figure 51). Deviation increases yearly, indicating that a higher degree of demand uncertainty exists now than in previous years. This is one example, but the trend is common among several areas.

Figure 51: RFC Summer Demand Regional Bandwidth's



Customer Behavior

Consumer demand is evolving in varying degrees, and it is difficult to predict the overall effects of customer behavior on long-term demand forecasts. On one hand, social "green" awareness programs and thrifty attitudes during economic downturns cause the general public to be conscious of their energy use, decreasing overall demand. Additionally, load demand will decrease as photovoltaic technology becomes more accessible to home owners.

On the other hand, the impact of economic fluctuations does not always persist over the horizon of the forecast. Furthermore the introduction of new technology and cultural patterns may increase load demand, varying by region. For example, the demand for electric vehicles is consistent with an increase in load demand within an area, increases the number of public charging stations, electric vehicles become more practical, thus increasing electricity demand.

The lack of clear and readily available leading indicators for these effects is the primary source of uncertainty. Additionally, the uncertainty of the forecasts should not be expected to correlate strongly with whether the forecast itself is for growth or decline in consumer demand. Specifically the following must be considered:

- **Economic outlook:** Changes in economic activity as measured by GDP are the primary positive driver of changes in electricity consumption. Uncertainty in economic forecasts corresponds positively to uncertainty in the load forecast.
- **New technology:** The introduction of new technology can be either a positive or negative driver of electricity consumption. The appearance of new types of loads (*e.g.,* electronic loads, electric vehicles) is a positive driver, whereas the appearance of compact fluorescent lights is a negative driver. Uncertainty in the rate of penetration of these technologies corresponds to increased uncertainty in the load forecast.
- **Consumer awareness:** Changes in consumer awareness of the cost and impact of energy consumption are a significant, but typically secondary and intermittent driver of changes in load

growth. Consumer awareness waxes and wanes with economic activity and with prices. The uncertainty in the impact of consumer awareness can be high, and the persistence of its impact is often very difficult to predict.

Overall, the combined effect of the expectations of change in load is additive with respect to the load forecast itself. However, the uncertainty in the expected change in load is more complex and highly sensitive to correlations in the contributing forecasts. In general, the combined expectations for two uncorrelated forecasts are as follows (where μ is the expected value and σ is the uncertainty in the expected value):

$$\mu_{total} = \mu_1 + \mu_2$$
$$\sigma^2_{total} = (\sigma_1 + \sigma_2)^2 = \sigma_1^2 + 2\sigma_1\sigma_2 + \sigma_2^2$$

The necessity for uncorrelated uncertainty contributions is a very important feature of any uncertainty estimation process that includes multiple sources of uncertainty. The process of estimating cross-correlation can only be done using historical analysis of past cross-correlations between the observations of various phenomena to be forecast. Either the sources of uncertainty can be shown to be uncorrelated phenomena or the contribution of cross-correlation ust be included in the estimate of uncertainty.

In considering customer behavior in the prediction of future demand, forecasters should not expect that the drivers enumerated above are uncorrelated. There is sufficient empirical evidence to suggest correlations such as the following:

- **Economic outlook and new technology:** Consumers are more likely to acquire goods and services that increase electric load during periods of economic growth and prosperity, which tends to drive a positive correlation in their combined uncertainty. But some new technologies replace less efficient old technologies, particularly following an economic downturn or during periods of high prices. This can give rise to an anti-correlated response in load growth and strongly correlated uncertainty between these two factors.
- **Economic outlook and consumer awareness:** Consumers become thriftier during periods of economic slowdown and periods of rising prices. Note that prices and economic activity are not necessarily correlated and can in fact be anti-correlated during periods of excessively fast economic recovery, so the uncertainty can be very difficult to estimate.
- **New technology and consumer awareness:** Consumer adoption of new technology is highly sensitive to consumer education. In general, there is a positive correlation between consumer education and the penetration of new technology.

Advanced Metering Infrastructure (AMI), Phasor Measurement Units (PMU), and the Smart Grid might help alleviate some of the challenges of forecasting by providing better customer data. However, better data does not always translate into reduced forecasting challenges. Instead, adding more choices for customers can make it more complex.

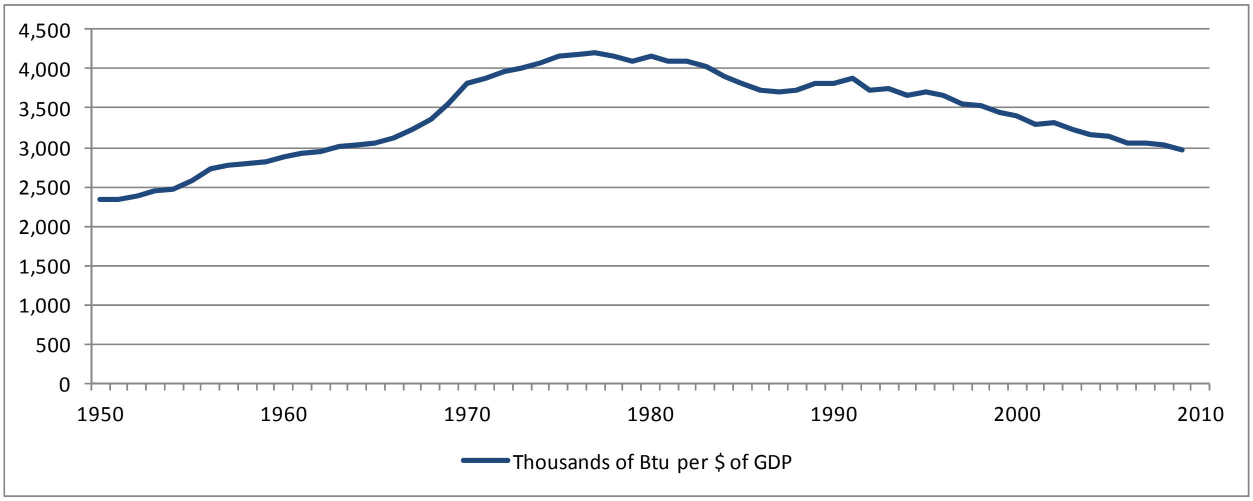
Even though AMI and Smart Grid technologies are being introduced across the country, industry continues to price their product using embedded cost averaging. Consequently, electricity prices do not embody price elasticity (Demand Response) across customer groups. Until embedded pricing is replaced by large-scale demand-sensitive pricing, no meaningful change in electricity consumption will occur from price elastic consumer behavior. In addition, once such large-scale pricing is introduced, forecasting will become more difficult – not less.

Another forecasting concern is using consumption patterns during periods of small price variation to extrapolate consumer behavior during periods of high price variation. For example, consumers have not yet been exposed to the large cost increases from expensive new capacity, carbon allowances, or large-scale renewable technologies. Some industry observers predict electricity prices may double in the future. But using past consumer behavior driven by much lower average (embedded) costs to project consumer reaction to higher demand-sensitive prices is futile.

Recent decreases in electricity use projections miss the likely increase in demand as consumer confidence returns. However, expecting a return to past consumptions trends may be mistaken for several reasons. First, past electricity use may have reflected highly leveraged income and wealth conditions that are no longer sustainable. Second, significantly higher electricity prices make investment in higher efficiency products to reduce electricity use (housing stock, housing size, appliances, etc,) comparatively much more economical. Finally, higher energy prices other than electricity – especially gasoline – may lead consumers toward a tipping point for adopting all forms of higher Energy Efficiency.

The figure below shows the long-run trend in efficiency. Admittedly, over this period U.S., manufacturing declined as a percentage of GDP, while the service sector increased as a proportion of domestic output. But the overall trend of electricity use per dollar of real output is clear: less electricity input per dollar of output. Industry observers suggest there remains considerable efficiency gains that are cost effective (long-run savings exceed long-run costs) – which suggests a continuation of the current trend toward greater Energy Efficiency (Figure 52).

Figure 52: Electricity and GDP

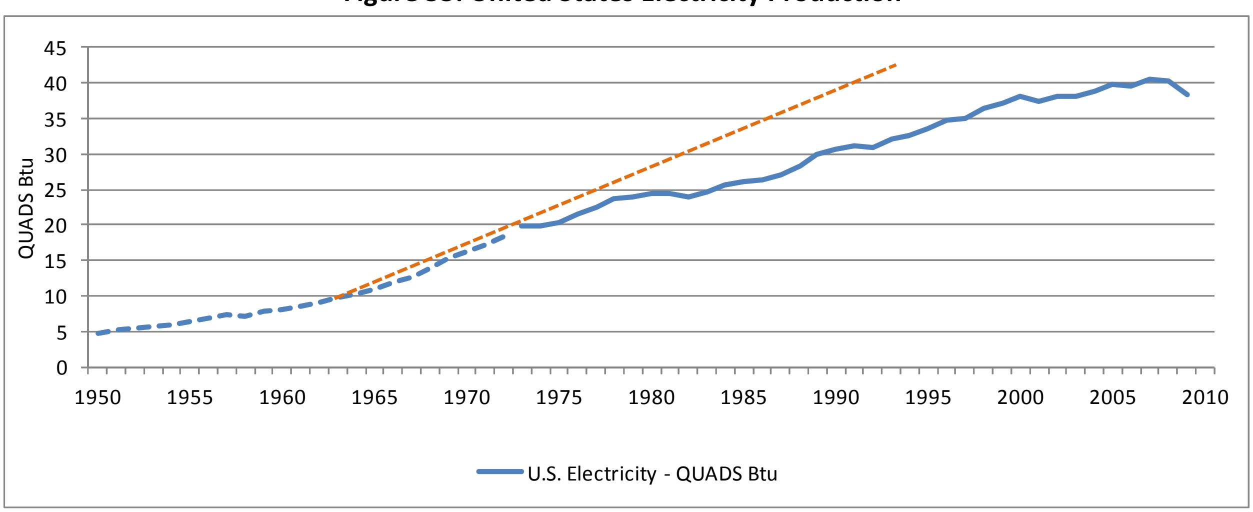


The historical record bears out the tipping point effect. In 1973, the first oil embargo led to consumers reducing their electricity use even though the "energy crisis" resulted from a temporary embargo of oil. Figure 74 shows the dramatic shift in electricity use from the 1973 oil shock.

Immediately after 1973, utility forecasts started to reflect decreased growth relative to their prior upward trend. As each successive year passed, the long-run forecast inched down toward the solid blue line until around the mid-1980s – nearly 10-years later – when forecasts shown by the solid green line began to overlay the actual consumption trend.

A permanent change had actually occurred in the electricity sector, but early analysis suggested that future use would be more *likely* to resume trend rather than decline to a new, albeit lower, trend. Electric utilities face the same question today: is the change in electricity use since the 2007 recession only temporary and soon to revert to its prior trend or is it a permanent change in consumer behavior like that encountered in the mid-1970s.

Figure 53: United States Electricity Production



Industry / Utility Behavior

It is uncertain how industry will react to new forecasting practices. Industry continues to employ econometric and regression methods to develop NEL and peak demand forecasts for long-run projections. These same utilities have broadened their techniques for *short-run* forecasting by using time series and neural networks, but these short-run techniques still rely on the age-old approach of minimizing the sum of squared residuals as the criterion to select the 'best' model.

Demand-Side Management programs, which include Energy Efficiency, Conservation, and Dispatchable and Controllable Demand Response, are used by industry to reduce demand.One of the key challenges in utility forecasting is separating the effects of utility-sponsored DSM programs from efficiency self-adoption made directly by consumers. The "Free Rider" problem and limited load research combine to make disentangling Energy Efficiency effects between utility-program DSM and consumer-adopted DSM difficult.

An equally difficult forecasting issue is what's known as the Slutsky Effect. In its simplest form, this effect means that price changes will affect income. The changed income will then, in turn, feedback on product demand. In the case of Energy Efficiency savings, because it can reduce ultimate energy prices, a price reduction therefore translates into additional income available for additional consumption. Consequently, the original Energy Efficiency investment that led to a price reduction will create additional income that will be spent, in part, on additional energy consumption. This effect explains why strictly engineering models typically overstate energy savings from DSM investments.

Behavior of External Forces

The present state of the U.S. economy presents new challenges and weakens the correlation between variables used in demand forecasting. Therefore, utility operators and reliability planners are investigating new economic variables to be used in forecasting.

Historically, industry used GDP variable in load forecasting. However, the correlation between United States GDP and energy demand is weakening, increasing forecast variability, thus, producing inaccurate forecasts, and making GDP a less reliable indicator for energy demand. Substituting economic variables may increase forecasting accuracy in the short-term planning horizon, but may become less accurate in the long-term planning horizon as the economy recovers. NERC should further assess the application of new economic variables introduced in load forecasting in the future.

The current Net Energy to Load (NEL) and peak demand bandwidths developed by the Load Forecasting Working Group (LFWG) addresses most, if not all, of these influences. The historical record includes considerable variation in weather, utility programs, consumer behavior, and external influences over many decades. Because the bandwidths use the actual NEL and peak demand variation caused by these influences, the bandwidths already capture their weighted impacts.

Most current regional conditions, although below previous regional forecasts, remain within the LFWG bandwidths. Additionally, the NEL and peak demand bandwidths are constructed with 80 percent confidence – a 10 percent chance actual use and peak will be above the upper bandwidth and a 10 percent chance actual use and peak will be below the lower bandwidth. Statistically speaking, then, in the long-run 2 out of 10 actual NELs is expected and peaks to be outside these bandwidths. Consequently, merely observing that some regions have actual conditions temporarily outside their bandwidths does not justify the conclusion that NEL and peak forecasts have become ineffective.

One other issue created by external forces is the movement of utilities between load regions. This, along, with changing of NERC reporting boundaries creates difficulties in the actual measurement of uncertainty. If a detailed history for the region is not precisely known, the uncertainty for a region could easily be over or underestimated, resulting in inefficiencies in the electric market. Any market inefficiency will directly translate to increased cost to the end-user and make planning for the regions more costly.

Weather Behavior

Weather is modeled in a number of ways, for example, in the SERC-N Assessment Area, an independent and matched-pair statistical test for the difference between means was conducted on annual cooling (CDD) and annual heating (HDD) degree-days from 1966-2010. The data were divided into two samples: 1966-1987 and 1989-2010 with 1988 omitted to make the number of observations the same in both samples. The results showed that both CDD and HDD were statistically higher and lower respectively for the latter period at 99 percent confidence. Of note, the *dispersion* of the latter sample was also larger from those of the earlier sample indicating greater temperature variability (i.e., uncertainty) compared with that of the earlier period. These results could indicate a local warming trend, poor temperature adjustments for surrounding infrastructure growth, relocation of temperature instrumentation, conversion from manual to automated temperature recordings, or some combination of all four. Given the statistical results for this specific geographic region, warmer mean temperatures are comingled with increased temperature dispersion. Even though mean temperatures are higher, their higher dispersion leads to increased variability and greater uncertainty. Given the statistical results for this specific geographic region, warmer mean temperatures are comingled with increased temperature dispersion. Even though mean temperatures are higher, their higher dispersion leads to increased variability and greater uncertainty.

Conclusion

With structural and cyclical effects of the recession continuing, demand forecasters are faced with the challenge of redefining methods to ensure accurate projections for both short- and long-term planning. As new variables are introduced to load forecasting models, further analysis will be necessary to gain a better understanding of their effects to short-run planning horizons, and ensure methods are consistent in long-term forecasting.

Many new technologies like AMI, PHEVs, and real-time pricing may provide better quality load data to utilities. However, in the near-term (1-5 years), these technologies may further contribute to the uncertainty due to changing residential customer behavior. Moreover, the benefits of these new technologies will not be realized until several years of baseline data have been collected in order to establish accurate residential profiles that can be relied upon for future forecasting.

Potential Impacts of Future Environmental Regulations

Summary

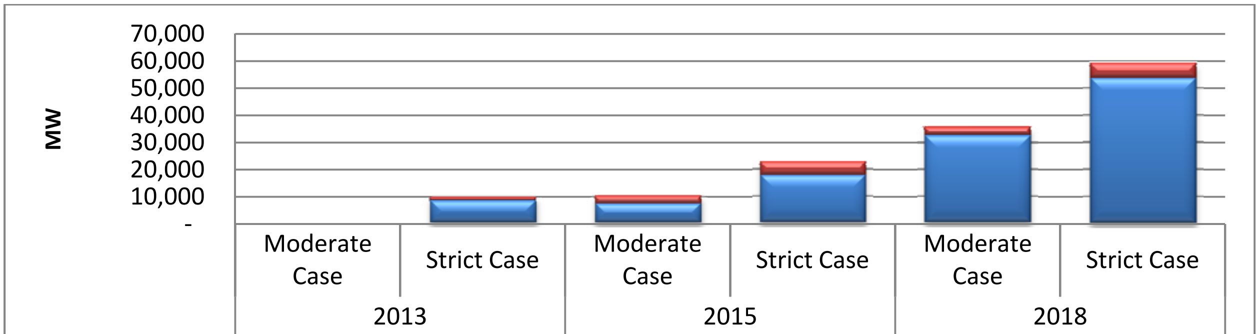
In the United States (U.S.), the Environmental Protection Agency (EPA) is in the process of promulgating four regulations: the proposed Coal Combustion Residuals rule (CCR rule), the proposed Mercury and Air Toxics Standards for Utilities, (Utility Air Toxics rule) the proposed Cooling Water Intake Structures § 316(b) rule (316(b) rule) , and the final Cross-State Air Pollution Rule (CSAPR).[119] In October 2010, NERC released an assessment of the potential resource adequacy effects of precursors to these proposed rules using 2009 bulk power system resource plan projections and demand forecasts. This 2010 assessment, entitled: *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (2010 NERC EPA Assessment), provided an independent and integrated preliminary perspective on the potential for the accelerated retirement of fossil-fired units under assumptions based on earlier versions of the rules or expectations about what the rules would contain.

While it is not possible to determine the exact impacts of these regulations until each regulation is finalized, many studies have been performed which attempt to predict the effects of these regulations as well as other economic factors driving retirements of electric generating units. This assessment, which is included as a companion study in this *2011 Long-Term Reliability Assessment*, updates the resource and demand forecasts used in the 2010 NERC EPA Assessment with the 2011 forecasts. Additionally, NERC revised the assumptions applied in its 2010 NERC EPA Assessment, taking into account new information that was not available at the time that report was prepared. Specifically, in this update, NERC used updated assumptions determined from proposed rules, as well as other viewpoints on how the rule will ultimately be carried out (*i.e.,* how states may implement regulations), to determine potential resource adequacy impacts. The expected retirements of electric generators are driven by many economic factors, not simply the cost of pollution control equipment.

While these updated results are provided for informational purposes to inform stakeholders and policy makers, they do not represent NERC's judgment on which units can, should, or will be retired. The two cases assessed are based on scenarios that represent a range of potential outcomes. Based on the results of the Moderate Case, 36 GW of incremental capacity in coal, oil, and gas-fired generation is identified for either retirement or for capacity reductions to support additional station loads (deratings) by 2018 (Figure 54). In the Strict Case, capacity reductions amount to approximately 59 GW. Of most important, however, are the retirements that may occur, as well as the retrofits that need to be implemented, by 2015, which are primarily driven by compliance deadlines in the proposed Utility Air Toxics rule.

[119] EPA promulgated the Final CSAPR on August 8, 2011 establishing a Federal Implementation Plan requiring 27 states to reduce power plant emissions of sulfur dioxide and nitrogen oxides that cross state lines and contribute to ozone and particulate pollution in other states. However, on October 14, 2011 EPA proposed technical revisions to the August 8th final rule, which are not yet finalized.

Figure 54: Incremental Capacity Reductions Due to the Combined EPA Regulation Scenario



	2013 Moderate Case	2013 Strict Case	2015 Moderate Case	2015 Strict Case	2018 Moderate Case	2018 Strict Case
Derate (MW)	-	1,217	2,770	4,996	3,174	5,584
Retired (MW)	-	8,574	7,491	17,844	32,589	53,574

This update concludes, however, that of these four rules, the 316(b) rule will have the greatest impact on the amount of capacity that may be economically vulnerable to retirement (approximately 25 to 39 GW) and, consequently, the greatest impact on Planning Reserve Margins, (Figure 55).

Figure 55: Incremental Capacity Reductions Due to Individual Rules

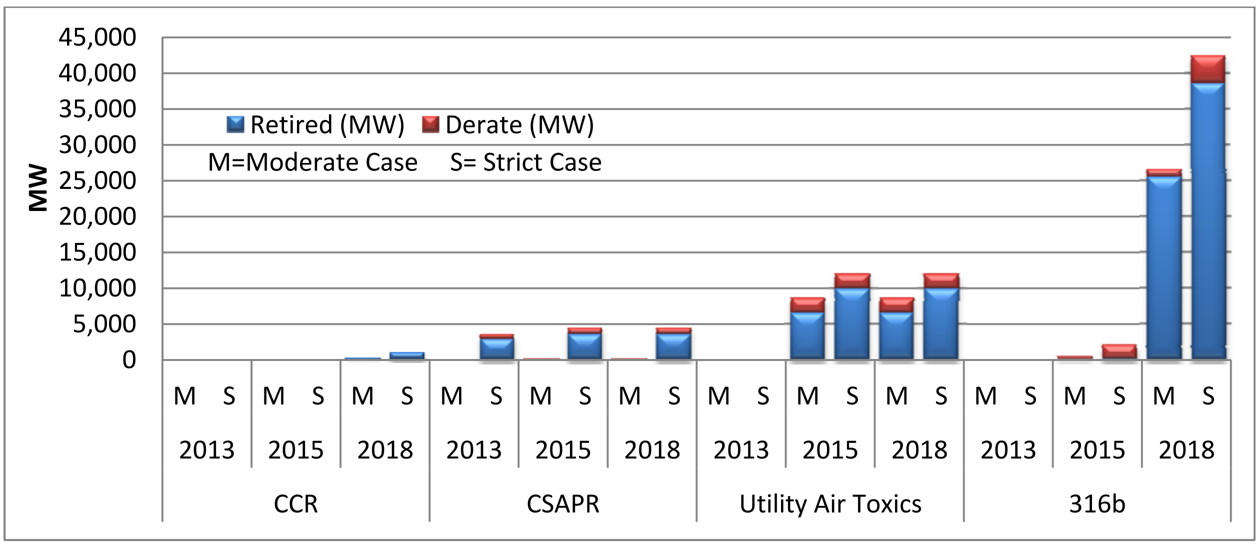
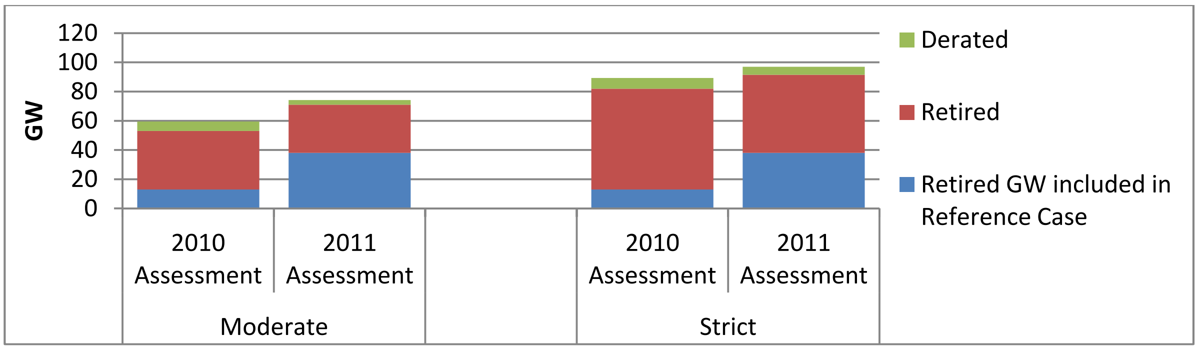


Figure 55, shows the respective rules' individual effects on retirements and derates. As the chart indicates, retirements or derates are not expected in 2013 under the Moderate Case. For the Strict Case, three of the four rules are not expected to cause any retirements or derates, and CSAPR is estimated to impact about 3.5 GW. In 2015, in the Moderate Case, CCR has no impact and the 316(b) rule impacts less than 1 GW due to their assumed compliance dates occurring beyond 2015. For 2015, the Utility Air Toxics rule alone would impact about 9 GW, in the Moderate Case, and could increase to about 12 GW, in the Strict Case.

When compared to the 2010 assessment, the results of this update show a net increase in the amount of potential decreases that can be expected by 2018 (Figure 56). While the potential impacts of compliance with EPA regulations presented in this update are less than those in the 2010 NERC EPA Assessment, a total of approximately 38 GW of generation capacity (23 GW of coal and 15 GW of gas/oil units) have already committed and/or announced plans to retire. While these generating units most likely announced plans to retire for a variety of reasons, a majority of these units were identified in the 2010 NERC EPA Assessment as economically vulnerable.

These retirement announcements and commitments have decreased the amount of assessed capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. In the 2010 NERC EPA Assessment, the amount of retirement announcements was 13 GW; 25 GW less than in this update. These plant retirements have already been considered in the Regional assessments and the reductions included in the 2011 LTRA Reference Case.

Figure 56: Comparison of Projected 2018 Capacity Reductions between 2010 and 2011 Study Results



For this update, NERC studied the effects on Planning Reserve Margins from both unit retirement (assuming retired capacity is not replaced) and retrofits, which cause capacity reductions due to increased station loads to support emission controls or new intake structures. If no action is taken to replace existing resources, signs of not meeting resource adequacy requirements appear to be most prevalent in the ERCOT Region. In ERCOT, the Anticipated Planning Reserve Margin falls below the NERC Reference Margin in 2013 (Figure 57); 2015 when considering Adjusted Potential Resources.

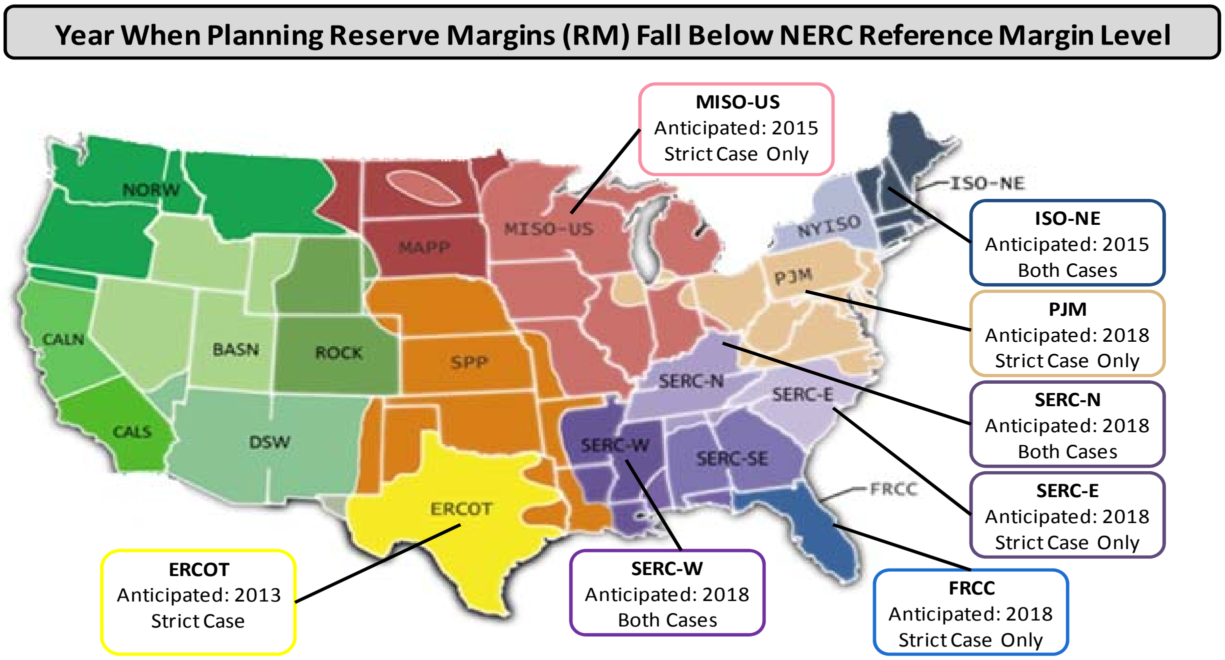
MISO and NPCC-New England show decreased Planning Reserve Margins below the NERC Reference Margin Level by 2015—FRCC, PJM, SERC-E, SERC-N, and SERC-W by 2018. These areas may need more resources than are currently planned in this assessment.

For some Assessment Areas, Planning Reserve Margins are below the NERC Reference Margin Level in the Reference Case as well. In these Assessment Areas, concerns even without applying scenario assumptions may exist. For example, in the 2011 Reference Case, the ERCOT and NPCC-New England Anticipated Planning Reserve Margins fall below the NERC Reference Margin Level in 2014 and 2015, respectively.

The impact on Planning Reserve Margins will be dependent on whether sufficient replacement capacity (or other system reinforcements) can be added in a timely manner to replace the generation capacity that is retired or lost. Unless additional resources are developed in certain Assessment Areas, beyond what is planned in the 2011 Reference Case, or additional time is provided to units needed to maintain

Planning Reserve Margins, bulk power system reliability could be affected. Implementation must allow sufficient time to construct new, or retrofit existing capacity, and allow the system to be planned and operated in accordance with NERC Reliability Standards and Regional Criteria at all times. Therefore, the timing of the rules must also consider the time needed for the industry to make incremental transmission upgrades and perform any other system reconfigurations that may be needed to maintain reliability. Additional time considerations should be made for the compliance period—the time period following the finalization of any particular rule.

Figure 57: Assessment Areas with Potential Resource Adequacy Issues



A significant retrofit effort is expected over the next ten years in order to comply with proposed EPA regulations. Environmental controls are expected to be put in place to meet air regulations by the end of 2015. In total, between 576 and 677 coal-fired unit retrofits (Moderate and Strict Case, respectively) will be needed by the end of 2015, totaling 234 to 258 GW of retrofitted coal capacity. Constricted compliance deadlines may challenge the electric industry's planning horizons, existing planning processes and typical construction schedules. Successful implementation of environmental regulations will be highly dependent on the ability of units needed for reliability to obtain the necessary time needed to comply with certain requirements. Given the timelines for compliance, many of the affected units may need to take maintenance outages concurrently. The need to take multiple units out-of-service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns during maintenance periods.

As discussed in the *Emerging and Standing Reliability Issues* section of this report, NERC identifies a number of tools the industry has available to mitigate potential reliability impacts from the implementation of EPA regulations. NERC's expectation is that industry and regulators will use these tools to ensure that bulk power system reliability is maintained as EPA regulations are finalized and implemented.

Recommendations

The following recommendations are pertinent to Federal and state regulators, the electric industry, as well as NERC, and supplement the 2010 NERC EPA Assessment:

Regulators:

- The Electric Reliability Organization's Reliability Standards and Regional Criteria must be met at all times to ensure reliable operation and planning of the bulk power system. Based on the results of this study, more time is needed in certain areas to ensure resource adequacy and local reliability requirements can be addressed during the transition and compliance period. EPA, FERC, DOE, and state utility regulators, working together and separately, should employ the array of tools at their disposal and their regulatory authority to preserve bulk power system reliability, including the deferral of compliance targets and granting extensions where there is a demonstrated reliability need. Coordination among Federal agencies is necessary to ensure the industry is not forced to violate one regulation to meet another.

Industry:

- Industry participants must meet NERC's Reliability Standards to ensure reliability and as they address compliance requirements of the EPA regulations. They should employ available tools and processes to ensure that bulk power system reliability is maintained through any resource transition. Toward that end, regional wholesale competitive market operators should ensure capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in areas without organized markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations. Additionally, affected unit owners that may be disconnected from wide-area planning functions (*e.g.,* generator owners operating in an ISO/RTO), should provide Planning Authorities timely and accurate information about the compliance plans for their units in order to adequately measure.

- Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed environmental control equipment. Outages for retrofits, new generation, and required transmission must be coordinated to ensure continued bulk power system reliability not only during peak periods, but during off-peak shoulder months when more scheduled outages are expected to occur.

NERC:

- NERC should continue to assess the implications of the EPA regulations as greater certainty emerges around industry obligations, technologies, timelines, and targets. Further, NERC should lead industry's effort and response to measure resource adequacy implications along with impacts to operating reliability (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) resulting from proposed and pending EPA regulations. NERC should leverage the expertise of the Planning Authorities to assess the local system conditions that could degrade reliability, review plans for meeting environmental regulations as well as NERC Reliability Standards, and submit recommendations to FERC on behalf of the industry.

Introduction

Future environmental requirements will have direct impacts on power supply decisions and grid reliability. The EPA is currently developing rules under its existing regulatory authority that could potentially require existing power suppliers to invest in retrofitting environmental controls at their existing units, or accelerate their retirement. NERC issued the *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (2010 NERC EPA Assessment) in October 2010 to address these concerns.[120] Since then, the EPA has issued proposed rules for Utility Air Toxics and 316(b) (impingement and entrainment of aquatic organisms), and finalized -CSAPR.[121] The 2010 NERC EPA Assessment recommended continued monitoring of pending EPA regulations, as greater certainty emerged regarding industry obligations, technologies, timelines, and targets.

Based on events that have occurred since the initial report was released, NERC has revised the 2010 modeling to reflect updated assumptions, with additional consideration for new information received from the industry. Building on the 2010 NERC EPA Assessment, this update compares resource plans provided by Regional Entities and Planning Authorities throughout the U.S. The differential will be granular, with a special focus on the Planning Reserve Margin impacts for each Assessment Area within the U.S. Differences will be measured to identify potential uncertainties in resource plans, and to better understand what decisions are yet to be made by NERC's stakeholders to address EPA's rulemaking.

Since publication of the initial report, the following material changes have occurred regarding the environmental regulation landscape in the U.S.:

- EPA proposed the Utility Air Toxics rule that includes limits on emissions of hazardous air toxics: particulate matter (PM) as a surrogate for non-metals, acid gases in the form of hydrogen chloride (HCl), and mercury. The Clean Air Act requires compliance with air toxics regulations within 3 years of a final rule, with extensions permitted under certain circumstances. Although extensions may be possible under the Clean Air Act, there is no guarantee they will be granted. It will be uneconomic for some units to retrofit to comply with the Utility Air Toxics rule and thus some units are expected to retire. Additionally, units being retrofitted with necessary controls may be unavailable for some time if retrofits cannot be completed prior to the compliance deadline.

- EPA proposed a Section 316(b) rule that includes implementation options that differ from those assumed in the 2010 NERC EPA Assessment. In the 2010 NERC EPA Assessment, cooling towers were assumed to be required in order to comply with the rule. The currently proposed rule, which includes separate impingement and entrainment requirements, may permit the applicability of modified technologies such as traveling screens for compliance with the

[120] http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

[121] EPA promulgated the Final Cross-State Air Pollution Rule on August 8, 2011 establishing a Federal Implementation Plan requiring 27 states to
reduce power plant emissions of sulfur dioxide and nitrogen oxides that cross state lines and contribute to ozone and particulate pollution in other states. However, on October 14, 2011 EPA proposed technical revisions to the August 8th final rule, which are not yet finalized.

impingement standard. However, the proposed rule would also require site specific entrainment studies, which would ultimately leave the final determination of compliance alternatives to each state. It is unknown how many facilities will be able to comply with the proposed rule without cooling towers.

- As a total replacement to the existing Clean Air Interstate Rule (CAIR), the proposed Clean Air Transport Rule (CATR) has been finalized with a variety of different requirements, titled the Cross-State Air Pollution Rule (CSAPR), including the addition of the state of Texas to the program. For this analysis, the rule does not allow the use of existing banked allowances for compliance and requires compliance with only limited trading without penalties starting in 2012.[122]

- Forecast demand and resource plans for the 2011-2021 assessment timeframe have significantly changed, directly affecting the Planning Reserve Margin projections.

- This update did not measure timelines for retrofitting to install needed environmental equipment, as this scheduling optimization is part of operational reliability. However, a large area view will be needed (potentially throughout the interconnections) for this schedule outage timing, to ensure sufficient operational reliability can be maintained while supporting bulk power system reliability.

These considerations and the potential reliability implications they pose to the industry have triggered a need for NERC to update the results of the 2010 NERC EPA Assessment, measuring the incremental implications resulting from these four EPA regulations (the proposed CCR Rule, proposed Utility Air Toxics Rule, proposed 316(b) Rule, and the final CSAPR). Additional rules that are not addressed but that may also impact assumptions would include the existing and expected Greenhouse Gas (GHG) requirements for new, modified, and existing sources, the Clean Air Visibility Rule (CAVR), and more stringent air quality standards.

Overall impacts on Planning Reserve Margins across the U.S. are assessed and areas below the NERC Reference Margin Level are identified. While the NERC analysis primarily focuses on the cumulative impacts of the four regulations, the impacts of each individual rule is also provided. These four regulations, plus other pending CO_2 regulations in the United States, are expected to go into effect on a staggered basis over the next ten years.

[122] This analysis does not consider the recent changes to CSAPR proposed by EPA, which would increase several state budgets and provide increased compliance flexibility. Proposed revisions to the rule are now being considered by the EPA: http://www.epa.gov/crossstaterule/techinfo.html

Background

In the U.S., several regulations are being promulgated by the EPA. Depending on the outcome of any or all of these regulations, the cost of compliance may result in early retirement of some fossil fuel-fired power plants. This update is designed to examine the potential reliability impacts, specifically concerning Planning Reserve Margins, from these environmental regulations.[123] The four regulations reviewed in this update are:

1) Clean Water Act – Section 316(b), Cooling-Water Intake Structures (316(b) rule)
2) Coal Combustion Residuals (CCR)
3) Cross-State Air Pollution Rule (CSAPR)
4) Title I, Clean Air Act –MACT –(Utility Air Toxics Rule)

Determinations on the cost of compliance were based on assumptions regarding potential regulations that have not been finalized by the EPA.[124] Ultimately, generation owners will determine the costs of compliance and make decisions about investments versus unit retirements; however, assumptions were intented to help stakeholders understand the potential impacts of these regulations.[125]

The 2010 NERC EPA Assessment examined the potential system resource adequacy impacts of these same four pending EPA regulations. This update estimated the future program requirements and the compliance measures that these four EPA rules would ultimately require. For two programs (CSAPR, CCR), the assessment was based upon draft regulations that had been issued during the summer of 2010. However, for the two other programs (316(b) and Utility Air Toxics), EPA had not yet developed draft regulations. For these two programs, the assessment was built upon extensive discussions of the possible program provisions with industry representatives, as EPA could not discuss their impending draft rules still under development.

Since the release of the 2010 NERC EPA Assessment, EPA has finalized one program rule (July 2011 C CSAPR, formerly proposed as the Clean Air Transport Rule). However, this rule is subject to revisions proposed by the EPA in October 2011. EPA has also issued draft rules for public comment for two pending programs—316 (b) Cooling Water Intake Structures (March 2011) and Utility Air Toxics Rule (May 2011). These revisions are sufficiently different from the 2010 estimates and this update reflects these program changes.

In addition, other market changes have occurred after the 2010 NERC EPA Assessment that have significant impacts on grid reliability. For example, demand forecasts for the period have been updated to 2011 projections. In some Regions, the demand forecasts have increased at a faster growth rate than prior projections, further reducing projected reserve margins. In addition, more generator owners have

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[123] Analysis performed by Energy Ventures Analysis, Inc. (http://www.evainc.com/) for NERC in September 2011 serves as the basis for this report.

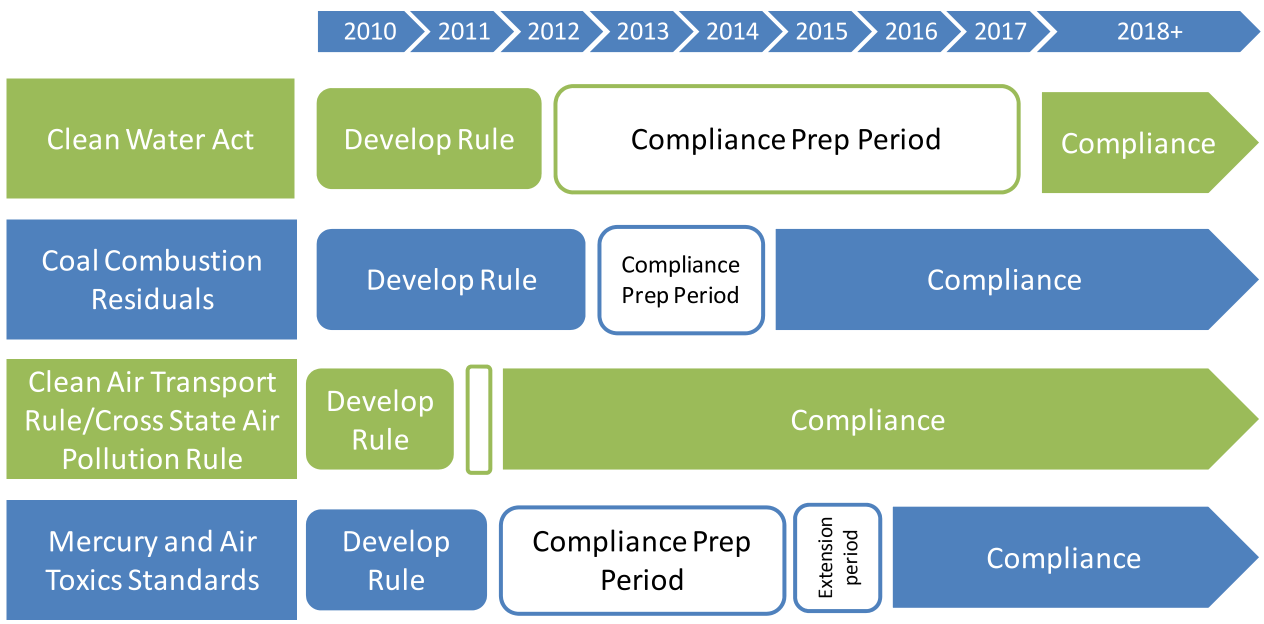
[124] Assumptions for Clean Water Act – Section 316(b), Cooling-Water Intake Structures, Coal Combustion Residuals (CCR), and Utility Air Toxics Rule were applied. The finalized Cross-State Air Pollution Rule (CSAPR) requirements were included in this analysis, but do not reflect the proposed changes to the Rule that EPA released in October 2011.

[125] The material in this report is provided for informational purposes and is not intended to reflect NERC's opinion on which units can, should, or will be retired—it is a scenario that reflects potential outcomes.

announced their unit retirement plans. These retirement announcements have decreased the available capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. Not surprisingly, most of the announced capacity retirements to date had been projected to retire within the results of the 2010 NERC EPA Assessment. However, there have also been some that were not projected to retire that have been announced since then.

A high-level timetable of rule implementation and compliance deadlines is presented below (Figure 58). In general, short compliance timelines can stress the bulk power system if requirements cannot be met by the compliance date. However, given a timeline that accommodates retrofit construction times and time to build or acquire additional resources, which may or may not include upgrades to the transmission system, both reliability and environmental goals can be met.

Figure 58: Projected Timeline for Regulation Development and Implementation

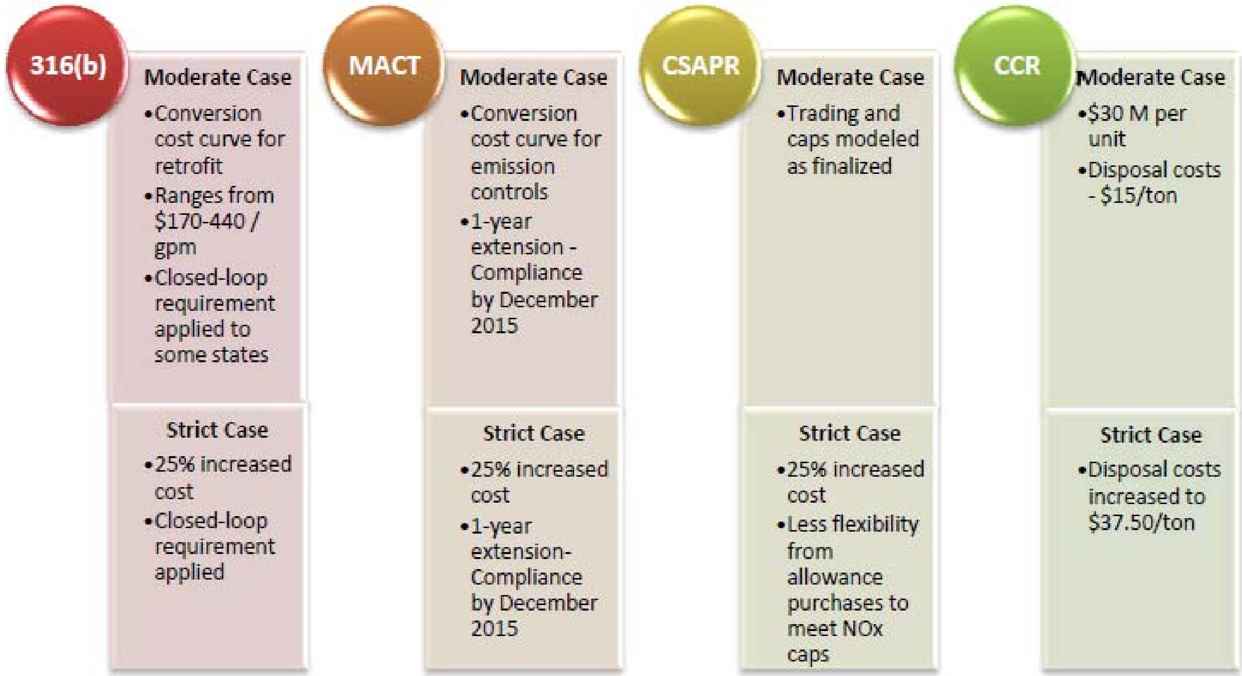


Reliability Assessment Study Design

This update focused on measuring the potential resource implications of the cumulative impact of the four proposed regulations and also seeks to identify cases where additional resources, beyond what is planned for in the 2011 Reference Case, may be required. The study objectives are as follows:

1. Identify and estimate potential future outcomes of four EPA rules.
2. Develop two cases (Moderate and Strict) to quantify the range of potential unit retirement risk from the aggregated impacts for 2013, 2015 and 2018
3. Examine the impacts of the unit retirement on Planning Reserve Margin (by Assessment Area)

Figure 59: Differences in Moderate and Strict Scenario Cases



Summary of Assumptions Used in This Report

The general approach used in this study assumes that there are only two choices to consider when complying with the new EPA regulations:

1. Retrofit the generating unit and continue operating;
2. Retire the generating unit and replace it with a greenfield natural gas unit

A more detailed discussion of this approach is included in the 2010 NERC EPA Assessment.[126]

This update does not provide consideration for the additional impacts of future greenhouse gas (GHG) control legislation, other state environmental control measures, national renewable portfolio standards (RPS), or other potential environmental rules and regulations.

This update also excludes any consideration of CO_2 legislation, and also assumes that there is no risk of future CO_2 legislation that will impact industry investment decisions. However, industry should consider the additional impacts from this type of legislation when making plant investment decisions. Depending on how power suppliers quantify these risks, unit retirements could result beyond those projected in this assessment.

Additional assumptions employed in this reliability assessment are as follows:

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[126] http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf
Using a different retirement method may produce different results. For instance, assessing merchant generation on future asset performance may potentially increase the amount of economically vulnerable capacity of retirement depending on the model input assumptions, if economics are unprofitable.

- Plant retirements already committed or announced (37.63 GW) are excluded. These retirement announcements and commitments have decreased the available capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. These plant retirements are already included in the 2011 LTRA Reference Case. Information and data on the 2011 LTRA Reference Case can be found in this report, with summarized data included in the *Estimated Demand, Resources, and Reserve Margin* section. Incremental capacity losses are assessed in this scenario.

- Assessment of the ability of the industry to permit, engineer, finance and build the required environmental controls within the required compliance timeframe was not included. However, implementation will place demands on the equipment and construction sectors since multiple EPA programs will be phased-in over the same timeframe. This situation is compounded by a significant number of electric generation units that are likely to retrofit environmental controls, and there will be competition created by replacement generation capacity projects and other heavy U.S. infrastructure projects in other sectors. Costs could escalate beyond the assumed compliance costs, should the EPA require compliance within three years of the final rulemaking dates. Therefore, the Strict Case includes an increase of 25 percent for the required control equipment.

- Compliance costs (*i.e.,* capital, O&M and performance changes) are based upon current average retrofit costs with existing technology market conditions. As noted above, the update does not assess any compliance cost risk impact caused by a run-up in labor and material from a large construction boom of environmental control and replacement power projects. By applying average retrofit control costs by size in lieu of a detail, site-specific engineering study, capital retrofit costs may over-or under estimate the cost at the site specific level.

- Increased CCR disposal costs can vary widely based upon site land availability, geology and state disposal permit requirements. An EPA assumption of onsite disposal is adopted, and the calculated disposal costs are similar to those employed in this update. However, if onsite disposal is prohibited (*i.e.,* land constraints, poor geology, etc.), the plant would incur additional costs to transport the ash and residuals to a properly permitted landfill, as well as tipping fees. These costs could be significant, but cannot be estimated without a site-specific analysis. For these reasons, sensitivity analysis is also performed for CCR disposal costs.

- Power suppliers will need to bring their units offline to tie in their retrofit environmental controls. During these periods, suppliers will lose potential revenues and may need to procure higher cost replacement power. While the capital and O&M costs are incorporated into the compliance decision, the replacement purchased power costs have not been included. These replacement costs are unlikely to change or accelerate unit retirement decisions, but would have the greatest effect on the nuclear plants that would incur the largest replacement power costs.

- For retrofit of once-through water cooling units, all nuclear plants are assumed to either become exempted, be subject to alternative investments, or else will be able to make the required investments. Therefore, no nuclear retirements are assumed in this update. This assessment does not include any derate effects for nuclear capacity from Section 316(b). However, the maximum loss of capacity due to derates of nuclear plants is estimated to be about 1.8 GW U.S.-wide.

- Under its draft Section 316(b) regulations, EPA left the authority to set fish entrainment standards (which are the regulatory driver for closed cycle cooling) to state regulators. With lack of a specific defined standard, compliance measures could range from low cost screens to very expensive recirculating cooling water systems. While state regulators have some flexibility in setting standards and can take reliability impacts into consideration, regulators are to use standards based upon recirculating cooling water systems as their default standard. For this update, an assessment of the states' past regulatory actions and current policies concerning closed cycle cooling were reviewed. The Moderate Case assumes that only states with "more-aggressive" water supply policies (accounting for 75 percent of affected capacity) would require recirculating water systems. In the Strict Case, all plants would require recirculating cooling water systems.[127] While closed cycle cooling is one of the options that states will consider under the guidelines required by the EPA, the proposed rule does not mandate closed cycle cooling. Given its large potential compliance cost and impact, this assumption may have the single largest impact in terms of the amount of capacity that may be economically vulnerable.

- In practice, generating units identified in this update as economically vulnerable may choose to wait until immediately prior to the compliance deadline before closing the generation unit. This ability to delay retirement may tend to act as a binary option with the effect that many units would retire on December 31 prior to a January 1 deadline.

- All combined cycle plants are assumed to make required investments and not be forced into early retirement. This may not be the case. For Utility Air Toxics, oil power stations are assumed to meet emission limits through availability of suitable quality specifications of refined oil products.

- This update excludes any fossil fuel market price or supply risks created by a large shift in the power generation mix from environmental compliance measures (*e.g.,* a shift from coal to natural gas fuel). Delivered natural gas and coal prices are fixed and do not change based on the level of retirements or the level of new replacement capacity that may be required.

- If a coal plant is retired under this method, there is nothing to prevent a secondary, after-the-fact decision. For instance, a coal unit may convert into a biomass-based unit, or convert to natural gas burners and continue operating as a steam plant. Also, plant owners may decide to invest in brownfield construction after retirement. Such analysis is beyond the scope of this update.

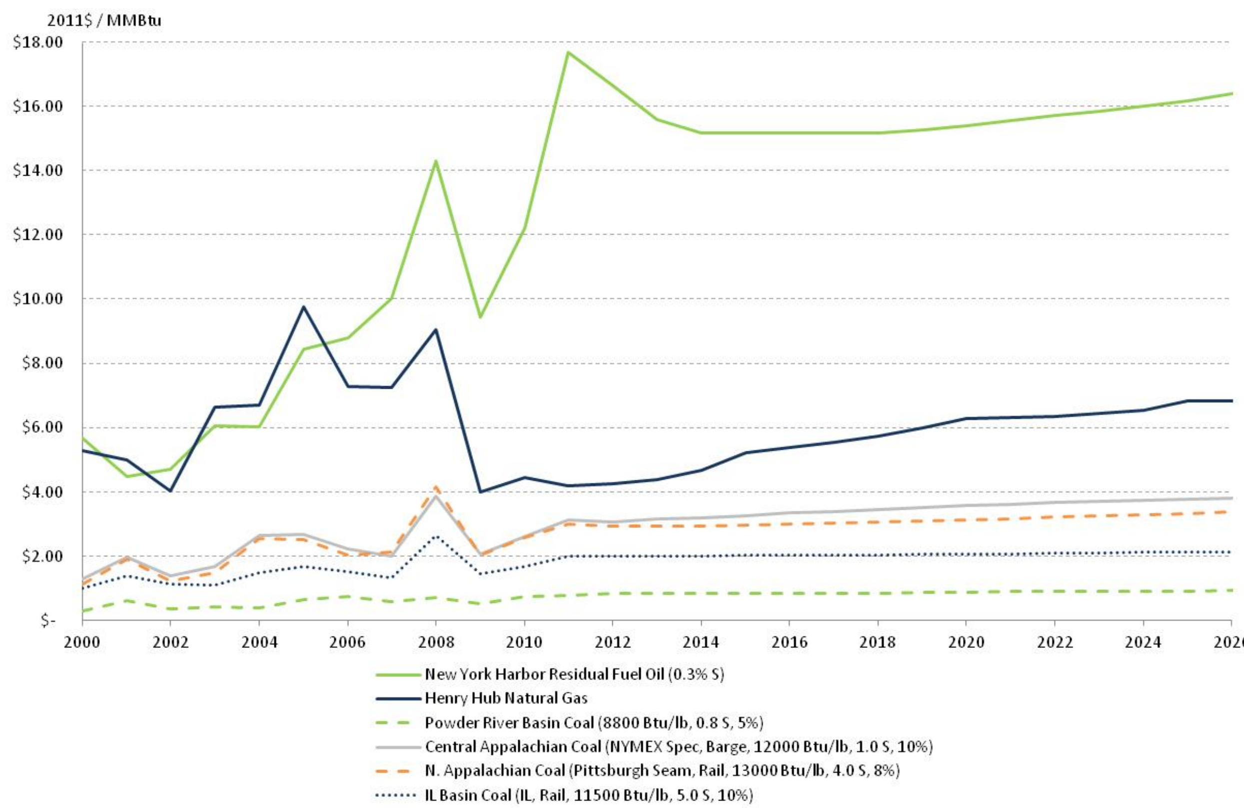
- Local reliability issues resulting from individual unit retirements were not studied. Operational reliability impacts, such as generation deliverability or stability, were not analyzed by NERC. For example, transmission system construction, enhancements, reconfiguration and development of

[127] While the requirement of mandating cooling towers for all open-loop cooled units is not explicitly noted in the proposed EPA rule and has a low likelihood of materializing, these assumptions provide a full spectrum of potential outcomes.

new operating procedures may be necessary in some areas, all of which can create additional timing considerations. However, some Regions and stakeholders within those Regions have assessed these concerns, and a summary of their findings are included in the *Regional Update* section.

- Delivered natural gas, coal and oil prices were based on the forecasts of Energy Ventures Analysis (EVA) as of October 2011. Ten-year forward averages are applied for 2013, 2015 and 2018. Varying these price assumptions may produce different results. The wholesale fuel price forecasts on an undelivered basis are depicted below (Figure 60). A sensitivity analysis to changes in natural gas commodity prices is presented in this update.

Figure 60: EVA Wholesale Wellhead Gas Price Forecasts

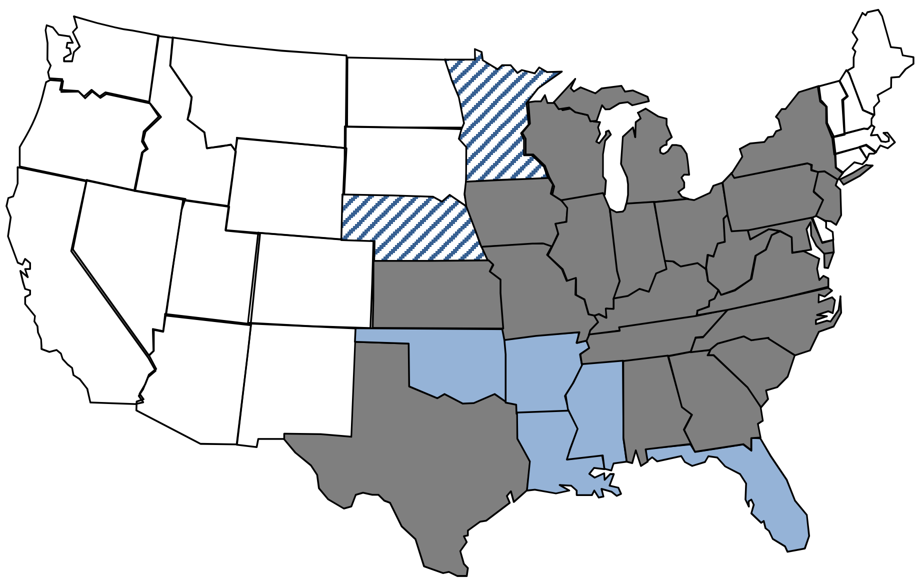


Current Status of EPA Regulations and Expected Outcomes

Cross-State Air Pollution Rule (CSAPR)

The EPA published its final CSAPR regulations on July 6, 2011, followed by the publication of proposed "technical corrections" in early October 2011. This rule was authorized under the 1990 Clean Air Act Amendments to address long-range transport of pollutants contributing to downwind non-attainment of fine particulate and ozone National Ambient Air Quality Standards. The EPA final rule creates three new pollutant cap and trade programs (SO_2, annual NO_X and seasonal NO_X) that will affect fossil fuel sources across a twenty-eight state region (Figure 61). Nearly 91 percent (259,603 MW) of the existing coal-fired capacity (excluding announced retirement plans) are located within this affected region. The first phase of CSAPR program will take effect on January 1, 2012 and targets an additional reduction in some state SO_2 emission budgets in 2014.

Figure 61: CSAPR State Programs

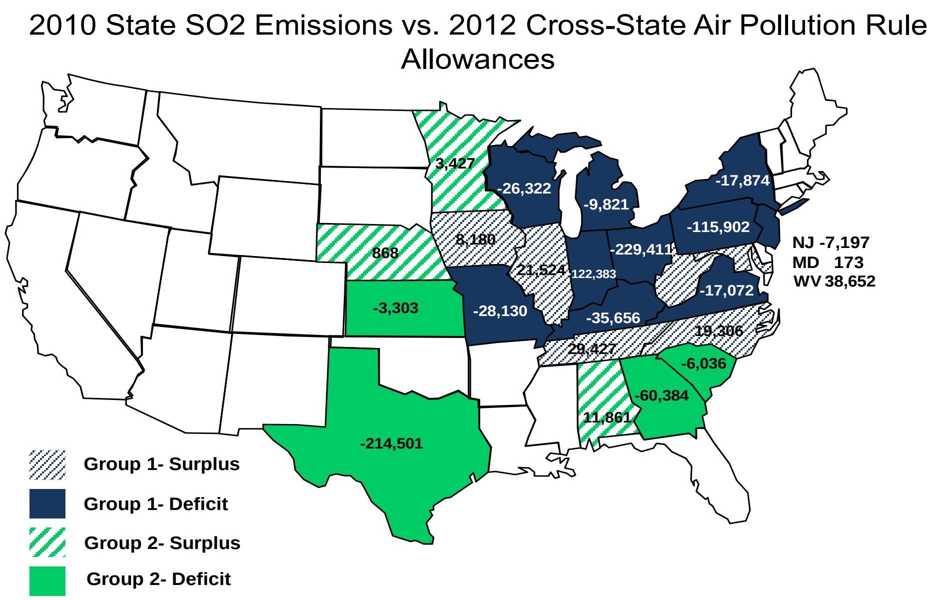


States controlled for both fine particles (annual SO_2 and NOx) and ozone (ozone season NOx) (21 States)
States controlled for fine particles only (annual SO_2 and NOx) (2 States)
States controlled for ozone only (ozone season NOx) (5 States)
States not covered by the Cross-State Air Pollution Rule

The additional emission reductions needed to comply are significant and highly concentrated to a few states (Figure 62). The constricted implementation period limits the available unit compliance options for meeting the 2012 emission caps. Companies are unable to permit and implement additional retrofit environmental control measures within 24-36 months, unless the construction phase has already commenced. Upgrades of existing flue gas desulphurization (FGD) equipment to enhance the performance of SO_2 removal and/or boiler upgrades enabling switching to lower sulfur fuels, will also take more than one year to engineer, permit, finance and implement. Insufficient time to retrofit units with necessary environmental controls[128] combined the anticipated initial shortage of surplus allowances offered for sale will potentially leave companies with limited options to satisfy compliance requirements by 2012. The remaining short-term emission reduction measures include converting coal units to natural gas or other zero emission generation or in some cases, accelerating unit retirement.

However, as a market-based cap and trade program, CSAPR does not mandate any specific controls, or control installation dates, on generating units. For example, any new pollution control retrofit installations desired by unit operators do not have to be operational on January 1 of 2012 or January 1 of 2014. Controls installed after January 1 of any year simply reduce the number of allowances needed by a unit for compliance during the balance of that year (and future years) and surplus allowances created become available for compliance to other generation units. Ultimately, NERC's modeling projects CSAPR impacts will cause significant displacement of coal-fired megawatts, especially in 2012 and 2013.

Figure 62: CSAPR Concentrated Emission Reduction Burden



While coal generation will likely be displaced, CSAPR alone may not directly cause unit retirement. Companies will still have the option to comply by operating affected plants on a shorter time-frame, while also ensuring that generators are available to provided capacity to support reliability, especially during peak seasons and other periods when capacity is needed. Few studies have been published that identify the specific impacts of CSAPR to the electricity industry, yet most conclude very limited impacts on coal-fired on-peak capacity. EPA's CSAPR analyses project only 4.8 GW in coal unit retirements.[129] Although CSAPR alone will not likely force unit retirements, plant owners may still elect to retire older

[128] Including the need to switch to lower sulfur fuels.

[129] Rule Regulatory Impact Assessment (RIA) for Final Air Transport Rule (June 2011) EPA, pg 262

coal-fired units with higher operating costs as early as next year to comply with CSAPR as part of a combined environmental compliance strategy.

EPA's final CSAPR rule included some significant program differences from its earlier July 2010 draft proposal. These differences (versus its earlier proposal analyzed in the NERC 2010 EPA Assessment) include stricter emission caps, added and eliminated states from the program and increased the overall compliance costs. These changes have accelerated some unit retirement decisions and triggered the idling of additional units.

This update assumes that the program will be implemented as proposed and promulgated by EPA in July 2011 and does not consider EPA's more recent proposed rule that proposes to: 1) delay the Agency's "assurance provision" requirements from 2012 to 2014 to assist in the transition from CAIR to the CSAPR; and (2) to increase nine state emission budgets to address state, industry and ISO requests for increased state emission budgets and to address a limited number of errors in EPA model input assumptions as well as a few instances in which EPA modeling did not adequately address local system constraints or localized rules that may require "out of merit" economic dispatch of some generating units at certain times during the year.[130] The changes proposed by EPA in October will help mitigate the impact of the rule, particularly in 2012 and 2013.

Section 316(b) Cooling Water Intake Structures

Cooling water intake operation and structures are regulated under Section 316(b) of Clean Water Act (CWA). The 316(b) rule is implemented by the state water permitting agencies through the National Pollution Discharge Elimination System (NPDES) permit program of the CWA. EPA provides state permitting agencies with regulatory guidance and standards to determine Best Technology Available (BTA) to protect aquatic life from impingement (being trapped against the intake screen) and entrainment (passing through the screens and into the plant's cooling water system).

The prior version of the 316(b) rule that applied to existing generation facilities (known as the "Phase II Rule) was promulgated in 2004 and applied only to facilities with water usage greater than 50 million gallons per day (mgd), of which at least 25 percent was for cooling purposes.[131] However, many aspects of the Phase II Rule were invalidated by the U.S. Court of Appeals in 2007 and the EPA withdrew the rule and directed the state permitting agencies to continue to implement the 316(b) rule on a site-specific basis using their best professional judgment.[132] EPA published a proposed Phase II rule on April 20, 2011 that it is required to finalize under a Consent Agreement by July 2012.

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[130] See October 14, 2011 "Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone" (76
FR 63,860).

[131] The EPA promulgated rules applicable to cooling water intake structures at manufacturing facilities in three phases: Phase I for new generation facilities, Phase II for existing large generation facilities, and Phase III for all remaining manufacturing facilities, including small electric generators. Phase I is in effect and requires that all new generation facilities install closed cycle cooling. Phase III has now been merged into the remanded Phase II rulemaking described herein.

[132] The U.S. Supreme Court did review one aspect of the U.S. Court of Appeals opinion in the Phase II Rule. The Supreme Court determined that the EPA has the discretion under Section 316(b) to utilize a cost-benefit test on a site-specific basis to determine BTA for each affected facility.

For this update, the final rule is assumed to be in effect by the end of 2012. However, the proposed rule incorporates an extended compliance period to meet both the impingement mortality (IM) and the entrainment mortality (EM) standards. These requirements will be implemented through the NPDES permit renewal process which occurs in five year cycles. Unlike the air rules, there will not be a single date on which all plants must be in compliance with the BTA standards. The proposed rule sets forth a number of interim deadlines prior to the time that BTA is to be installed and operating. These are intended as milestones to ensure that the facility is obtaining the necessary site-specific data and performing the analyses required to determine the BTA for IM and EM. For facilities that were covered under the now-remanded Phase II Rule, the proposed rule provides for a five-year period (representing the initial permit term after the rule takes effect) to gather data about the facility and its cooling water intake structure and the source water body, to design and conduct an entrainment characterization study, and to perform technical feasibility and a cost–benefit analysis. The ultimate compliance date will vary by plant and will be determined by the state permitting director.

The 316(b) rule will apply to all current and future nuclear and fossil steam generating units, accounting for over 83 percent of 2010 U.S. generation. However, the greatest impact will be on those existing plants that have once-through cooling systems. Over 1,200 units with once-through cooling water systems were identified through EIA Form 923 and the older Form 767 (*Steam Electric Plant Operation and Design Report*) data filings by power generators. The affected units include 754 coal units, 405 oil/gas steam units and 42 nuclear units (60.5 GW). Generators such as peaking turbines, hydroelectric facilities, wind turbines, and solar PV panels do not use steam as the prime mover for generating electricity and, therefore, do not require additional water for cooling purposes. These generators are not subject to the requirements of this rule.

Major EPA rulemaking policy issues that could affect electric grid reliability are:

- Implementation period
- Applicability to existing structures
- BTA – the final IM and EM standards

In the original Phase II Rule, EPA established a flexible and cost-effective process that had no measurable effect on steam electric generating unit retirements. However, due to the need to meet the deficiencies determined by the Court of Appeals, the proposed rule is substantially different. It is also noted that in its opinion upholding the cost-benefit aspects of the Phase II Rule, the U.S. Supreme Court determined the EPA retains significant discretion in designing the rule.

However, EPA's 2011 draft 316 (b) rule is substantially different. The 2011 draft rule will require all steam generating stations to meet BTA standards for both fish IM and EM. The proposed 316(b) rule has two IM compliance alternatives for affected plants – strict numeric IM standards (not more than 31% mortality in any month and 12% on an average annual basis) or a velocity no greater than 0.5 fps at the cooling water intake. For those facilities that were not designed with the prescribed intake velocity, IM compliance will involve either a fish return system by means of a retrofit of the plant's travelling screens, or a diversion device like a velocity cap or a wedge wire screen attached to the intake pipe. While the EPA recognized the effectiveness of closed cycle cooling as the most effective means of reducing IM via flow reductions, it did not propose it as BTA for IM because it is not available at all facilities and modified traveling screens are more cost-effective. The EPA has received significant comments from industry expressing concerns that even with state-of-the art traveling screens, it will be impossible to meet the numeric IM standards at some facilities due to site-specific conditions. In response, the EPA has indicated that it is reconsidering the IM standards to include an alternative technology standard. Under this alternative, facilities could install a pre-approved technology as BTA, including screens or a diversionary technology, and would be deemed compliant in lieu of meeting the numeric IM standards.

In its rule development, EPA had assumed this standard could be met by using modified traveling screens. However, some existing power plants that employ EPA's modified traveling screens technology have been unable to meet the proposed fish mortality standard. If the EPA does not include such an alternate technology standard in the final rule, IM compliance options would be severely limited at some plants and may require significant intake structure retrofits to meet the intake velocity of no greater than 0.5 feet per second. Should this not be available to a plant, the EPA-proposed strict fish IM standard may effectively force recirculating cooling water systems options independent of the site specific BTA entrainment standard.

Regarding the EM standards, the EPA did not designate closed cycle cooling, or any technology, as BTA. Rather, due to the site- specific nature of determining BTA for EM, the EPA delegated this determination to the state permitting directors.

EPA's draft 316(b) rule also contained four different approaches to setting a fish EM standard. Two of the proposed entrainment options would require affected facilities to have "***flow reduction commensurate with closed cycle cooling as BTA for entrainment***". Although not the preferred EPA option, these options represent the highest compliance cost policy outcome and were incorporated in the Strict Case of this update.

The other two options (including the preferred option) provide for BTA entrainment controls to be determined on a site specific basis. This policy approach allows EPA not to quantify specific BTA entrainment cost impact, since entrainment would remain undefined and left up to state regulators. The challenge for NERC's Moderate Case scenario is how state regulators will develop the BTA entrainment standards. EPA rules require states to follow an entrainment standard that reflects "maximum reduction in entrainment mortality" warranted after consideration of nine relevant factors. In other words, closed-cycle systems are EPA's default BTA technology unless other listed relevant factors make recirculating systems unfeasible. The nine factors are:

- Numbers/type of organisms entrained
- Entrainment impacts on waterbody
- Quantified and qualitative social benefits and costs
- Thermal discharge impacts
- Impacts on reliability of energy delivery within the immediate area
- Changes in particulate emissions and other pollutants associated with entrainment technologies

- Land availability
- Useful plant life
- Impacts on water consumption

However, of these factors, EPA only considered four issues to be important for the national standard BTA determination:

- **Energy reliability**—Grid reliability can be a cumulative impact from multiple retirements and not necessarily from any one facility contribution, except for local reliability concerns. Also, the projected reliability problem must occur in the "immediate area." Given the grid and industry's attempt to improve reliability, there is a significant risk that very few cases may qualify for different treatment under this provision. Because of the site-specific evaluation, a comprehensive, system-wide reliability study will be difficult to incorporate into an individual unit's effect on reliability.

- **Increased air emissions on a local basis associated with entrainment technologies**—Given that utility MACT will be in place prior to 316(b), emission increases from lost energy efficiency may not be significant or much different than new plant emission rates. EPA discussion also concludes that cooling tower emission effects would generally be limited to facility property and not an issue, with very few exceptions.

- **Land Availability**—EPA in its preamble states it has not identified any electric generating facility with more than 160 acres per GW capacity that EPA believes would be unable to construct retrofit cooling towers and that some facilities on smaller land parcels would still be able "to install closed cycle cooling by engineering creative solutions." This EPA criterion would suggest that the vast majority of power plant sites have sufficient land for cooling tower construction. As is the case with this update, EPA admits it lacks data to analyze land constraints, but quotes an Electric Power Research Institute (EPRI) report that indicates six percent of sites investigated had insufficient space for cooling tower systems. However EPA also suggests that higher cooling system retrofit difficulty does not mean that cooling towers would not be BTA, but would also depend upon the projected system benefits.

- **Remaining useful life of the facility**—EPA's preamble example is for a unit that would be shut down in 3 years versus 20 years. The NERC analysis already takes remaining lifetime into account in its analysis. However, the net impact may be that EPA uses this provision to force retirements within a negotiated time period. In either case, the oil/gas steam units, which are not used often, will be retired anyway.

Without a specific entrainment defined standard, regulators could set entrainment standards ranging from low cost screens to high cost recirculating cooling water systems.

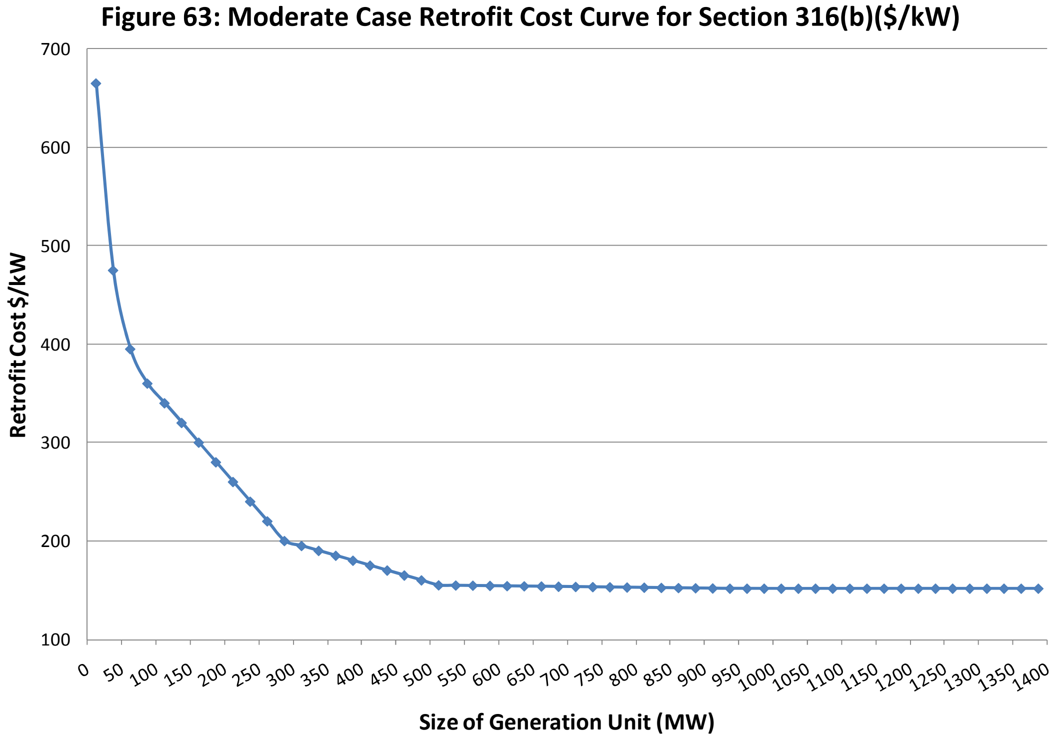
To gauge how strict state regulators would set the entrainment standard in the Moderate Case, an assessment of past state water supply and water permitting practices was made.[133] This review found Alabama, Arizona, California, Delaware, Florida, Georgia, New Mexico, New York, New Jersey, Texas and states in New England (accounting for 75 percent of affected capacity) have raised water supply concerns in the past that could potentially result in their regulators requiring recirculating water systems to meet the fish entrainment. The remaining states (25 percent of affected capacity) were assumed to require a combination of screens, barriers and seasonal flow limitations to comply with their fish entrainment standards.

Capital cost to convert from once-through cooling water to recirculating cooling water systems are derived from three prior engineering studies and industry cost surveys:

- EPRI's *Issues Analysis of Retrofitting Once-through Cooled Plants with Closed Cycle Cooling* (10/07)
- Maulbetsch Consulting EPRI Survey (7/2002) of 50 plant estimates
- Stone & Webster Study (7/2002) for Utility Water Assessment Group.

These studies found that capital conversion costs are directly tied to the once-through cooling water pumping rate and heavily influenced by site layout and local conditions. Conversion costs ranged from $170-440 gallons per minute (gpm) (in 2010 dollars), with an average capital conversion cost of $240 gpm. The average conversion costs were applied for most locations, except for known urban locations having constrained site conditions for which a 25 percent higher capital cost estimate of $300 gpm was applied. The base case costs applied in this update are shown below (Figure 63).

Figure 63: Moderate Case Retrofit Cost Curve for Section 316(b)($/kW)



133

In addition to the capital conversion costs, the station would lose both capacity and energy with larger power consumption used to drive the cooling water pump. The capacity and energy losses estimated in the 2008 DOE study and applied in this update are shown below (Table 31).

Table 31: Capacity Derating/Energy Penalties Due to Cooling Tower Conversion

Assessment Areas	Average Energy Loss %	Capacity Derating Penalty %
ERCOT	0.80%	2.50%
FRCC	0.90%	2.50%
MRO	1.40%	3.10%
NPCC	1.30%	3.40%
NYPP	1.20%	3.20%
PJM/MISO	1.60%	3.40%
SERC-W	0.90%	2.60%
SERC-SE	0.80%	2.40%
SERC-N	0.90%	2.60%
SERC-E	1.00%	2.80%
SPP	1.00%	2.80%
WECC-DSW	1.40%	2.70%
WECC-CALN/CALS	0.90%	2.50%
WECC-NWPP/WECC-BASIN	1.40%	3.00%
RMPA	0.00%	2.50%
Total	1.20%	2.90%

Source: DOE *Electric Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units* (10/2008)

The capital costs for the more flexible screen alternatives for the remaining alternatives were based upon preliminary EPRI cost estimates.

Under these policy interpretations, 25-35 GW of older oil/gas unit steam generating units (Moderate to Strict case) are estimated to be economically vulnerable for retirements in lieu of making the large capital retrofit investments in recirculating cooling water systems alone. These results are higher than EPA's published results in its March 2011 report *Economic and Benefit Analysis for Proposed Section 316(b) Existing Facilities Rule* (EPA 821-R-11-003). The EPA study assumed that only 1 GW of existing capacity would retire earlier by 2028 under its preferred option and 14 GW are projected for retirement earlier under its stricter forced recirculating system policy options. The EPA study did not quantify specific BTA entrainment cost impact under its preferred option as the entrainment standard would be determined by state regulators applying the nine criteria set forth in the proposed rule.

These referenced compliance costs and reliability impacts may be underestimated. First, the published studies used to develop the average capital cost estimates are based upon surveys done in 2002 and 2007. Open-loop to closed-loop conversions are rare and no historic cost data has been published. Since these surveys, the costs of environmental project construction have escalated. Second, the site-specific conditions and plant layout can have significant impacts on conversion costs that are not reflected by applying industrial average estimates. Although an adjustment was made for known constrained urban sites, several more sites likely exist that may have similar (but unknown) site constraint considerations. Finally, given the rule implementation period and the large amount of affected power plants (252 GW), demand for labor and construction materials for conversions could be in high demand and result in real cost escalation. Such capital cost run-ups have occurred in pollution control projects in the past. To capture these potential risks, the Strict Case scenario includes a 25 percent real price escalation in the average conversion cost to $300 gpm at most locations and $400 gpm at known constrained urban site locations.

Coal Combustion Residuals

Concerns raised by the December 2008 TVA Kingston ash spill and its widespread environmental impact triggered EPA consideration of changing regulating coal ash and waste byproduct (*e.g.,* scrubber sludge) disposal from its current special waste designation to Subtitle C Hazardous Waste under the Resource Conservation and Recovery Act. EPA issued a draft rule on the disposal of CCRs for public comment in June 2010. A final rule has still not been issued. For this study, the final rule is assumed to be completed in 2012 with implementation expected to start in 2013-2015 and full compliance by 2018.

This EPA rule is expected to regulate 136 million tons per year of coal ash and solid byproducts currently produced by the coal-fired stations. Major policy issues that will impact electric grid reliability include:

- hazardous waste designation of coal ash
- impoundment design standards
- groundwater protection standards
- rule implementation period.

EPA has proposed conversion of all coal ash handling systems from utility-boilers to dry based systems. Two options were provided for disposal of all ash and coal byproducts in a landfill, meeting either Subtitle C or D, which entails different types of waste disposal standards, and to close or cap existing ash ponds. Such a ruling may cause up to 359 coal units (128.5 GW) to convert their wet ash handling systems to dry based systems, incur greater ash disposal costs for the 136 million tons per year (TPY) of ash disposal, and close and/or cap the existing 500 ash ponds in operation.

In addition, a hazardous waste designation under Subtitle C would likely eliminate the market for 20 million tons of ash currently resold into the market. However, EPA is considering a “special waste” designation that would allow “beneficial” reuse of the substance to continue. Hazardous waste designation without exceptions would expand the existing hazardous waste disposal market from its current size of 2 million tons per year.

Prior public studies examining the ash disposal issue on power plant operation are limited. To provide context for this assessment, a 2009 EOP Group Study titled *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal fired Utilities* was reviewed. This 2009 industrial study concluded that EPA’s draft rule could directly affect operations at 397 coal-fired generating units (175 GW). The EOP Group study estimated bottom ash conversion costs of $30 million per unit and this assumption are used in the Moderate Case of this assessment. In addition, at some stations, the ash ponds also dispose of fly ash (15 million TPY) requiring an additional

$3 billion investment to convert from wet to dry handling systems. Outside conversion costs, stations would need to build alternative wastewater treatment facilities at 155 facilities ranging in cost from $80 million without a flue gas desulfurization system (FGD) to $120 million with an FGD per facility. These conversions would provide storm water and/or FGD scrubber sludge treatment currently handled by the ash ponds. Ash pond closure costs were estimated to be $30 million per pond.

However, the 2009 EOP Study contained some deficiencies that could underestimate compliance costs, as it excluded costs for:

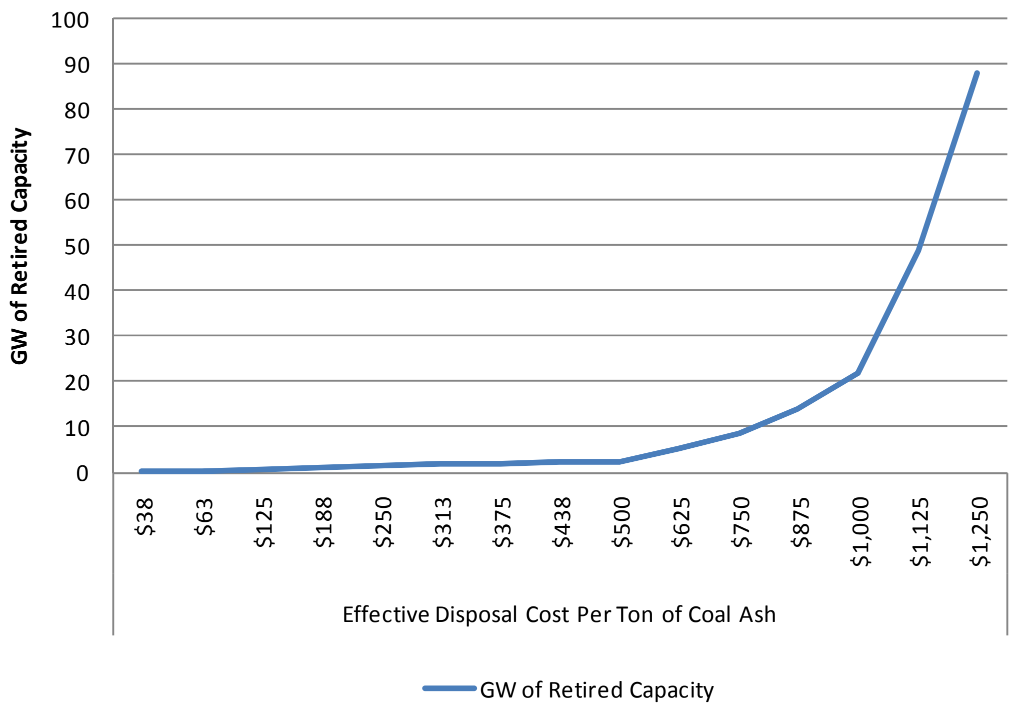
- Land acquisition for a landfill or expanded wastewater treatment facilities.
- Increased disposal if ash was designated as hazardous waste.
- Existing ash pond closures.

Remediation costs will vary significantly based upon the extent of any groundwater contamination, site geology and aquifer use. However, any remediation might be considered as a sunk cost since it would be incurred independently of the future operating decision and would not be incorporated into the power supplier's unit retirement decision.

A total of 359 units (128.5 GW) of coal-fired capacity reported using wet pond based systems for their ash and/or byproduct handling systems in their EIA Form 767 and 923 filings. For these units, the 2009 EOP study cost estimates for bottom ash conversion and wastewater treatment upgrades are applied on an individual generator basis. The additional EOP ash waste disposal costs of $15 per ton for handling in a regulated non-hazardous onsite landfill were added to the unit operating costs in the Moderate Case of this update. The pond closure and remediation costs are assumed to become sunk costs that would be incurred independent of the future power plant operations. Therefore, only incremental costs tied to ongoing operations are accounted for in the decision to invest or retire the unit. When these incremental power production costs exceeded new replacement capacity costs, the units became potential retirement candidates.

To account for potential underestimation of investment requirements and based upon conversations with various utilities, the capital compliance cost uncertainty is likely to be +/-25 percent. To account for potentially higher costs under stricter Subtitle C guidelines, landfill costs are assumed to be much higher at $37.50 per ton (2010$) in the Strict Case, which is also similar to the EPA study's estimated disposal costs. Further, in lieu of conducting site-specific analyses, a sensitivity analysis is performed across a wide range of ash disposal costs from $37.50 up to $1,250 per ton (Figure 64). The costs are believed to be contained well within the flat slope portion of the line on the far left side. However, the additional costs that may become associated with distance removal of the hazardous substance to existing certified landfills could drive costs upward.

Figure 64: Sensitivity of Retirements as a Function of Higher Assumed Coal-Ash Disposal Costs due to Coal Combustion Residuals regulations



Utility Air Toxics Rule

Under Title I of the 1990 Clean Air Act, EPA is obligated to develop an emission control program for listed air toxics for sources that emit at, or above, prescribed threshold values. For the power sector, the listed air toxics of greatest concern are mercury (coal), acid gases (coal), arsenic (coal), vanadium (oil) and chromium (oil). EPA had originally developed a cap and trade program for controlling mercury emissions. However, the U.S. Court of Appeals overturned this initial program in 2008 and concluded that the Clean Air Act specifically required EPA to develop Maximum Achievable Control Technology (MACT) emissions standards for air toxics listed in the Clean Air Act and did not allow a cap and trade program. The Act was specific in how these MACT emission rate limitations were calculated (*i.e.,* average emission rate of lowest emitting 12 percent of the source population) and how quickly they were to be implemented (*i.e.,* 3 years after final rule with up to a one year extension waiver).

The Clean Air Act requires existing plants to comply with the Utility Air Toxics Rule as expeditiously as practicable, but in no event later than three years after the effective date of the rule. The proposed Utility Air Toxics Rule provides the maximum amount of compliance time permitted by the Act. The Act authorizes EPA or a state with an approved Title V permitting program to grant a one-year extension of time "if necessary for the installation of controls." In addition, the Act authorizes the President to exempt a source from compliance for a period of not more than 2 years if the President determines that "the technology to implement such standard is not available and that it is in the national security interests of the United States to do so." Finally, EPA can exercise its enforcement discretion under the Act to allow more time if a source has justified the need for an extension.

EPA published its draft Utility Air Toxics Rule in May 2011 and has announced that it will issue its final regulations in December 2011. Assuming that the one year extension is granted when needed, power suppliers will have until December 2015 to design, permit and implement the needed measures to meet the emission rate limitations for acid gases, mercury and non-mercury metals. This assumption is used in both the Moderate and Strict Cases. All coal-fired power plant units must meet the emissions standards at each unit: allowance trading between units and reduced unit use are not compliance options.

In its draft proposal, EPA proposed the acid gas rate limitation for existing coal-fired units to be either (1) 0.002 lbs of hydrochloric acid per MMBtu, or alternatively (2) 2.0 pounds of SO_2/MWH (0.20 lbs SO_2/MMBtu). Given the US coal chlorine content for the major producing basins, this limit effectively requires bituminous and lignite coal-fired units to retrofit a FGD scrubber (at $400-$900/kW) and a dry sorbent injection ($50/kW) or spray dry scrubber ($400-$900/kW) on sub-bituminous coal units. Roughly 72.5 percent of existing coal-fired capacity have existing FGD equipment or have announced plans to retrofit such equipment. The remaining 27.5 percent (89 GW) of uncontrolled existing capacity could be forced to retrofit with FGD controls or retire by December 2015. Given 29 GW have already announced their retirement plans, scrubber decisions to meet acid gas limitations by 2015 remain for 60 GW of uncontrolled coal-fired capacity.

In addition, the proposed EPA Utility Air Toxic rule also includes a total particulate emission limitation of 0.03 pounds (lbs)/MMBtu as a surrogate for non-mercury metals, which is applicable to coal-fired units. Given the average ash content of coals, this limit will require power plants to remove 99.6-99.8 percent of the particulate matter in the flue gas stream. Such high performance can only be achieved on a consistent basis by fabric filter controls that cost between $200-$400/kW to retrofit. Given that 75 percent of US coal-fired capacity does not have, nor has announced plans for such controls, the compliance costs will be significant for those plants to continue producing power beyond 2015. The 2011 Edison Electric Institute[134] study has made a similar assumption. In contrast, EPA analyses[135] suggested up to 30 percent of coal units with electrostatic precipitators may be able to meet the particulate limit without retrofitting fabric filter controls. As a result, EPA projects a much lower 166 GW of existing coal-fired capacity would retrofit fabric filter controls under this rule.

EPA proposed a mercury emission standard of 1.2 lbs/TBtu for units that burn non-lignite coal and 4.0 lbs/TBtu for lignite-fired units. These limits will likely be met with the forced FGD controls for acid gas compliance and could require activated carbon injection systems ($15-$25/kW retrofit capital cost) for lignite and sub-bituminous coal units. Plants that burn coals with high chlorine content (bituminous coal) that are equipped with SCR and newer wet FGD units may be able to achieve the proposed mercury emission standard without activated carbon injection (ACI.) While such controls will add to plant operating costs and may eliminate ash reuse applications, the capital cost for mercury controls alone is unlikely to require any additional coal unit retirements.

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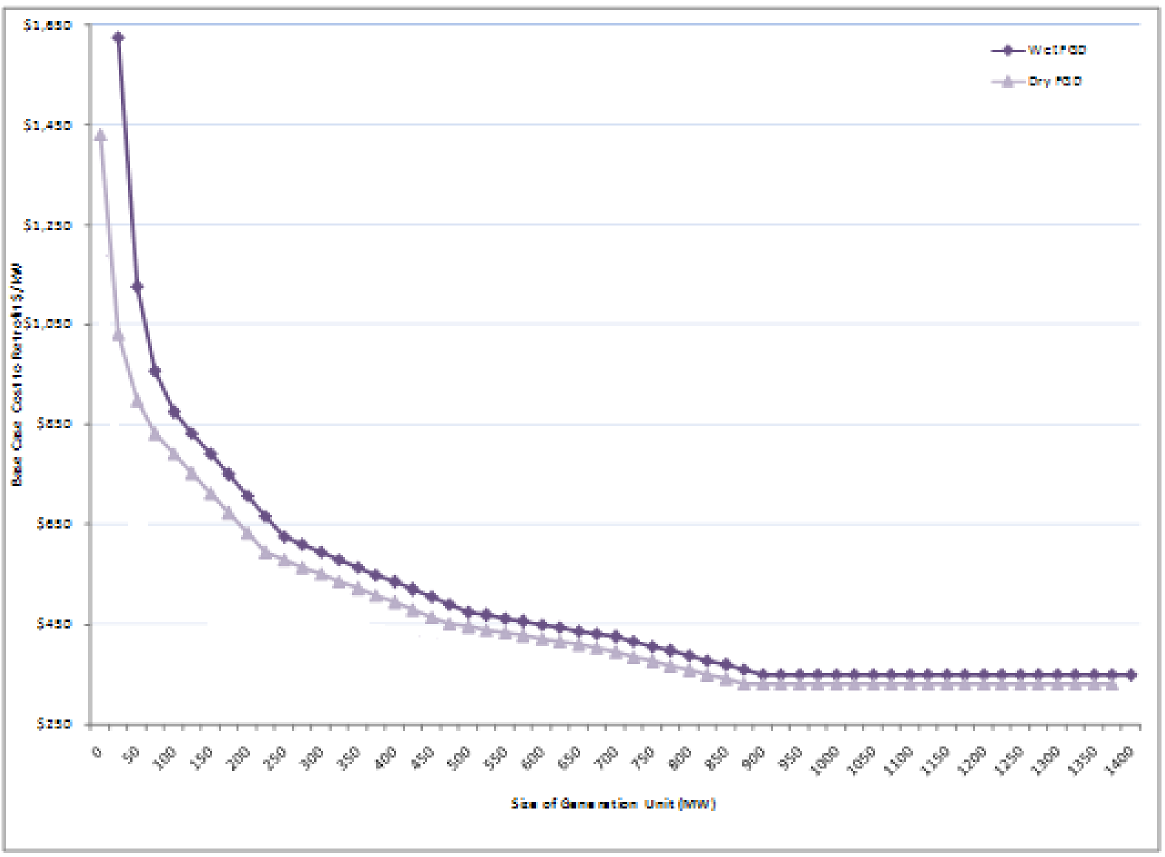
[134] Potential Impacts of Environmental Regulation on the US Generation Fleet (Jan 2011) ICF for EEI pg 43

[135] Regulatory Impact Analysis of the Proposed Toxics Rule: Final Report (EPA March 2011)

The analysis in this update applies environmental control cost curves to develop unit-specific compliance costs estimates. The increased production cost, due to the new pollution controls, are then compared to unit production costs of replacement power. In the Moderate Case of this study, investments are made on existing coal units when FGD and fabric filter equipment are not present, or planned. Also, halide treated activated carbon injection (HACI) systems are added for lignite and sub-bituminious coal types. These control retrofit costs were developed for an average difficulty plant. The retrofit capital cost curves for FGD and fabric filter controls are shown below (Figure 65 and Figure **66**). Oil-fired units (109.7 GW) are assumed to meet their air toxic limits through tighter oil specifications at the refinery. Compliance costs increase by 25 percent in the Strict Case.

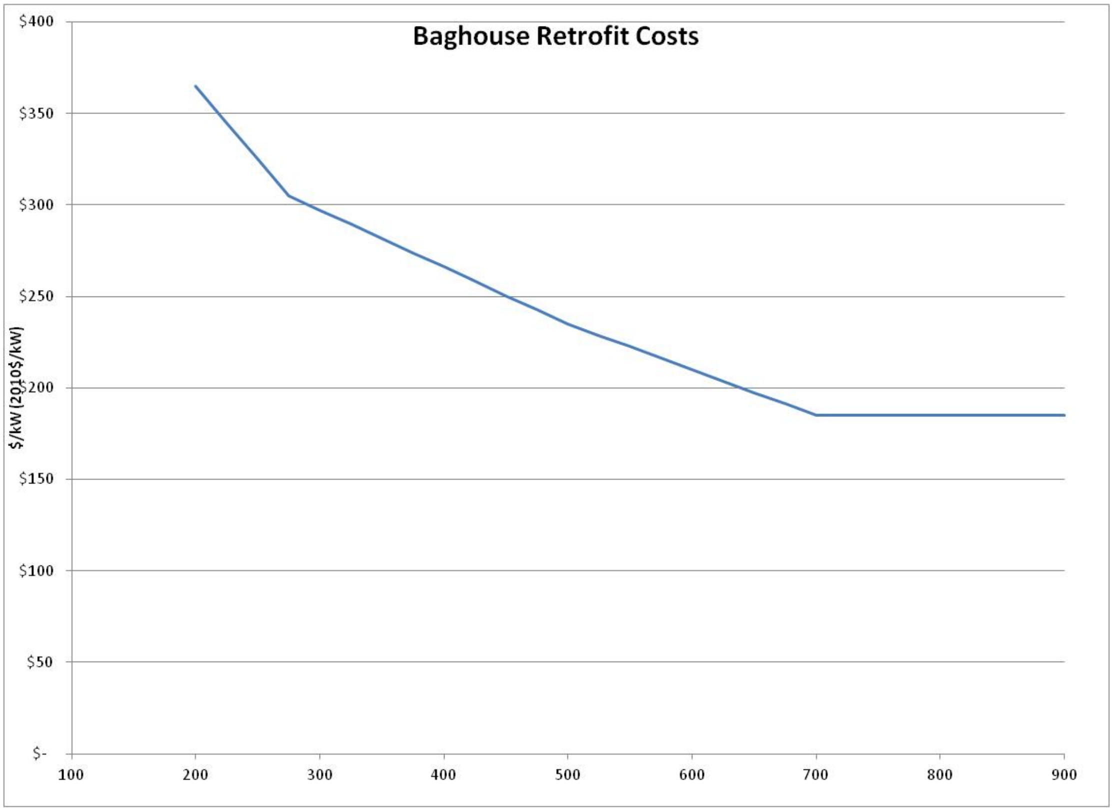
The combination of the three contaminants of the Utility Air Toxic Rule will require a large capital investment in scrubbers, fabric filters and activated carbon injection systems that EPA estimated would cost $10 to 11 billion per year to finance, build and operate. The EPA analysis assumed that 9.9 GW of coal-fired capacity would retire from the draft rule alone.[136]

Figure 65: Average FGD Retrofit Capital Costs



[136] IBID

Figure 66: Retrofit Capital Cost for Baghouse/Fabric Filter Control Systems on Coal-Fired Power Plants



Integrated and Cumulative Effects of Environmental Regulation Compliance

Power industry unit retirement decisions will not be based upon any single factor, but the combined effect from all the EPA regulations, economic conditions, and potential future requirements (*e.g.,* from stricter national ambient air quality standards for SO_2, ozone and fine particulate, carbon control, national clean energy standards, effluent guidelines, etc.) that may be proposed over the remaining lifetime of the power plant facility.

EPA regulations may require existing coal-fired capacity to make capital investments to add control technologies to address air, waste, and water regulations. Those coal-fired units that determine these control modifications are not cost-effective will retire sooner. With natural gas prices becoming more competitive with the emergence of low cost shale gas, generators may be unable to fully recover their retrofit environmental investment costs and may elect to retire higher cost coal-fired capacity.

The cumulative effect of the four EPA rules is provided below (Table 32 through Table 34) for 2013, 2015 and 2018. As is shown in Table 32, an additional 11.4 GW of coal-fired capacity retirements is projected by 2013, due mostly to the combination of the Utility Air Toxics Rule and CSAPR. While these units are expected to retire under the Utility Air Toxics rule assumptions, the dates are accelerated to provide the needed incremental reductions needed for CSAPR compliance strategies.

By 2015, the bulk of the remaining coal-fired capacity retirements are projected to comply with the December 2015 Utility Air Toxics Rule deadline (noting that this update assumes that certain units are able to gain a one-year extension). As shown in Table 33, between 3.6 and 24.4 GW of coal-fired capacity is economically vulnerable by 2015. This table quantifies only the incremental impact and excludes the 37.6 GW of already announced and committed retirements—some of which have been directly attributed to the environmental regulations.[137] The measurement used in this assessment is Planning Reserve Margins, which provide an indication for the need for additional resources to maintain bulk power system reliability. Further, this assessment does not take into account local reliability affects resulting from individual unit retirements, such as transmission system voltage or stability impacts, nor the additional costs of transmission facilities required to support reliability.

In this update, the assumed compliance deadline for 316(b) rule is 2018. These rules are projected to trigger large amounts of older oil/gas-fired steam generating capacity retirements as well as retirement of some older coal-fired units that have already added sufficient environmental controls to meet the Utility Air Toxics and CSAPR requirements, but would be unable to justify the combination of needed cooling tower retrofit investment and higher ash disposal costs. The total economically vulnerable capacity could reach 36 GW under the Moderate Case, and up to 59 GW in the Strict Case (Table 34). However, total capacity reductions will depend on the degree to which state regulators mandate closed-loop cooling system.[138]

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[137] These units faced economic challenges based on a variety of reasons, including gas-prices and demand forecasts. In addition, some plants have announced retirements as a result of previous settlements with government agencies requiring the installation of pollution controls to comply with regulations other than the four that specifically assessed in this report.

[138] Impacts of individual rules are provided in the Additional Background Information section.

Table 32: Cumulative Projected Incremental Capacity Losses through 2013

	Moderate Case Projections				Strict Case Projections		
	Combined Impacts - 2013				Combined Impacts - 2013		
	Moderate Case				Strict Case		
	Derated (MW)	Retired (MW)	Total		Derated (MW)	Retired (MW)	Total
Coal Units				**Coal Units**			
ERCOT	-	-	-	ERCOT	76	-	76
FRCC	-	-	-	FRCC	13	-	13
ISO-NE	-	-	-	ISO-NE	-	-	-
NYISO	-	-	-	NYISO	12	-	12
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	387	1,679	2,066
PJM	-	-	-	PJM	225	3,173	3,398
SERC-N	-	-	-	SERC-N	61	264	325
SERC-W	-	-	-	SERC-W	100	75	175
SERC-SE	-	-	-	SERC-SE	72	1,555	1,626
SERC-E	-	-	-	SERC-E	14	1,018	1,032
SPP	-	-	-	SPP	256	811	1,067
CAL-N	-	-	-	CAL-N	-	-	-
CAL-S	-	-	-	CAL-S	-	-	-
Basin	-	-	-	Basin	-	-	-
Desert SW	-	-	-	Desert SW	-	-	-
RMPA	-	-	-	RMPA	-	-	-
NWPP	-	-	-	NWPP	-	-	-
TOTAL	-	-	-	TOTAL	1,217	8,574	9,791
O/G-ST Units				**O/G-ST Units**			
ERCOT	-	-	-	ERCOT	-	-	-
FRCC	-	-	-	FRCC	-	-	-
ISO-NE	-	-	-	ISO-NE	-	-	-
NYISO	-	-	-	NYISO	-	-	-
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	-	-	-
PJM	-	-	-	PJM	-	-	-
SERC-N	-	-	-	SERC-N	-	-	-
SERC-W	-	-	-	SERC-W	-	-	-
SERC-SE	-	-	-	SERC-SE	-	-	-
SERC-E	-	-	-	SERC-E	-	-	-
SPP	-	-	-	SPP	-	-	-
CAL-N	-	-	-	CAL-N	-	-	-
CAL-S	-	-	-	CAL-S	-	-	-
Basin	-	-	-	Basin	-	-	-
Desert SW	-	-	-	Desert SW	-	-	-
RMPA	-	-	-	RMPA	-	-	-
NWPP	-	-	-	NWPP	-	-	-
TOTAL	-	-	-	TOTAL	-	-	-

Table 33: Cumulative Projected Incremental Capacity Losses through 2015

	Moderate Case Projections			Strict Case Projections		
	Combined Impacts - 2015			Combined Impacts - 2015		
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
Coal Units						
ERCOT	267	-	267	267	-	267
FRCC	176	-	176	156	1,592	1,748
ISO-NE	93	144	237	88	239	327
NYISO	77	74	151	77	74	151
MAPP	8	-	8	10	0	10
MISO	519	1,110	1,629	1,400	3,583	4,982
PJM	606	2,850	3,456	1,323	5,725	7,048
SERC-N	175	724	899	435	1,690	2,125
SERC-W	95	0	96	95	265	360
SERC-SE	318	1,358	1,675	265	2,942	3,206
SERC-E	110	808	918	303	945	1,248
SPP	198	187	385	415	285	700
CAL-N	4	15	18	2	67	68
CAL-S	4	83	87	-	184	184
Basin	29	39	68	35	39	74
Desert SW	34	-	34	34	-	34
RMPA	23	89	111	53	203	256
NWPP	34	12	46	40	12	52
TOTAL	2,770	7,491	10,261	4,996	17,844	22,840
O/G-ST Units						
ERCOT	-	-	-	-	-	-
FRCC	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-
NYISO	-	-	-	-	-	-
MAPP	-	-	-	-	-	-
MISO	-	-	-	-	-	-
PJM	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-
SPP	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-
Basin	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-
RMPA	-	-	-	-	-	-
NWPP	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

Table 34: Cumulative Projected Incremental Capacity Losses through 2018

	Moderate Case Projections			Strict Case Projections			
	Combined Impacts - 2018				Combined Impacts - 2018		
	Moderate Case				Strict Case		
	Derated (MW)	Retired (MW)	Total		Derated (MW)	Retired (MW)	Total
Coal Units				**Coal Units**			
ERCOT	267	-	267	ERCOT	267	-	267
FRCC	176	-	176	FRCC	156	1,592	1,748
ISO-NE	93	144	237	ISO-NE	88	239	327
NYISO	77	74	151	NYISO	77	74	151
MAPP	8	-	8	MAPP	10	0	10
MISO	519	1,110	1,629	MISO	1,400	3,583	4,982
PJM	606	2,850	3,456	PJM	1,323	5,725	7,048
SERC-N	175	724	899	SERC-N	435	1,690	2,125
SERC-W	95	0	96	SERC-W	95	265	360
SERC-SE	318	1,358	1,675	SERC-SE	265	2,942	3,206
SERC-E	110	808	918	SERC-E	303	945	1,248
SPP	198	187	385	SPP	415	285	700
CAL-N	4	15	18	CAL-N	2	67	68
CAL-S	4	83	87	CAL-S	-	184	184
Basin	29	39	68	Basin	35	39	74
Desert SW	34	-	34	Desert SW	34	-	34
RMPA	23	89	111	RMPA	53	203	256
NWPP	34	12	46	NWPP	40	12	52
TOTAL	2,770	7,491	10,261	TOTAL	4,996	17,844	22,840
O/G-ST Units				**O/G-ST Units**			
ERCOT	119	5,065	5,184	ERCOT	105	5,593	5,698
FRCC	27	904	931	FRCC	27	904	931
ISO-NE	4	4,898	4,901	ISO-NE	-	5,015	5,015
NYISO	201	4,096	4,297	NYISO	195	4,291	4,486
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	-	424	424
PJM	-	903	903	PJM	2	3,632	3,634
SERC-N	-	-	-	SERC-N	-	-	-
SERC-W	-	-	-	SERC-W	190	3,134	3,324
SERC-SE	-	237	237	SERC-SE	-	349	349
SERC-E	-	-	-	SERC-E	-	84	84
SPP	-	-	-	SPP	29	2,523	2,551
CAL-N	-	2,138	2,138	CAL-N	-	2,138	2,138
CAL-S	48	6,439	6,487	CAL-S	36	6,924	6,960
Basin	-	-	-	Basin	1	113	114
Desert SW	5	418	423	Desert SW	2	523	525
RMPA	-	-	-	RMPA	-	84	84
NWPP	-	-	-	NWPP	-	-	-
TOTAL	404	25,097	25,502	TOTAL	588	35,730	36,318

Capacity losses modeled in this analysis are highly sensitive to changes in natural gas prices. All the projected capacity losses outlined above were projected using EVA's Base natural gas and delivered coal prices. For the 2018 case, sensitivity studies were run to quantify the sensitivity of the retirement decisions to a range of +/- $2.00/MMBtu from the EVA Base Henry Hub (HH) natural gas price. In addition, EVA has developed high and low natural gas price forecasts that reflect our interpretation of a 90 percent confidence level incorporating the full range of reasonable potential outcomes of market, technology and regulatory changes. Sensitivity of the 2018 coal unit retirements (excludes derate capacity losses) are shown below (Table 35).

Table 35: Projected 2018 Coal Retirements Based on Gas-Price Sensitivity

Year	Base - $2 NG Price $/MMBtu	Low HH NG Price $/MMBtu	Base HH NG Price $/MMBtu	High HH NG Price $/MMBtu	Base+ $2 NG Price $/MMBtu
2013	$2.47	$4.27	$4.53	$5.07	$6.60
2014	$2.82	$4.72	$4.92	$5.50	$7.02
2015	$3.42	$5.31	$5.54	$5.84	$7.67
2016	$3.65	$5.49	$5.81	$6.19	$7.96
2017	$3.89	$5.68	$6.08	$6.56	$8.26
2018	$4.15	$5.88	$6.37	$6.93	$8.59
2019	$4.51	$6.08	$6.76	$7.32	$9.02
2020	$4.89	$6.28	$7.17	$7.71	$9.45
2021	$4.99	$6.49	$7.31	$7.99	$9.62
2022	$5.11	$6.70	$7.46	$8.28	$9.81
2023	$5.30	$6.91	$7.69	$8.58	$10.07
2024	$5.50	$7.13	$7.92	$8.89	$10.34
2025	$5.92	$7.36	$8.37	$9.20	$10.83
2026	$6.02	$7.52	$8.50	$9.45	$10.99
2027	$6.11	$7.69	$8.63	$9.71	$11.16
2028	$6.20	$7.86	$8.75	$9.97	$11.31
2029	$6.31	$8.03	$8.90	$10.23	$11.49
2030	$6.44	$8.21	$9.06	$10.51	$11.69
Moderate Case (MW)	**13,261**	**9,879**	**7,491**	**7,062**	**5,678**
Strict Case (MW)	**34,570**	**19,755**	**17,844**	**14,390**	**10,665**

Note: Base-$2 HH and Base+$2 HH vary by $2 Real from base Henry Hub

A significant retrofit effort is expected over the next ten years in order to comply with proposed EPA regulations. Environmental controls are expected to be put in place to meet air regulations by the end of 2015. In total, between 576 and 677 coal-fired unit retrofits (Moderate and Strict Case, respectively) will be needed by the end of 2015, totaling 234 to 258 GW of retrofitted coal capacity (Table 36).[139] For water regulations, a majority of the retrofits are expected to be performed beyond 2015. While the compliance date for 316(b) is assumed to be in 2018, retrofits are likely to continue into 2020 and beyond depending on the individual circumstances and requirements for each plant; therefore, these retrofits are not shown.

[139] These values do not include retrofits that would be needed to meet 316(b) compliance.

Table 36: Retrofits Needed by End of 2015 (by Number of Units and Capacity)

	2015			
	Moderate Case		Strict Case	
	Number	MW	Number	MW
ERCOT	23	13,424	27	15,720
FRCC	16	7,357	17	7,436
ISO-NE	8	1,808	6	1,713
NYISO	9	1,890	10	1,890
MAPP	2	419	5	1,120
MISO	138	51,979	156	55,038
PJM	120	54,669	148	59,195
SERC-N	56	19,238	70	21,500
SERC-W	9	5,520	9	5,520
SERC-SE	34	19,503	43	20,822
SERC-E	31	14,156	35	15,048
SPP	59	22,106	65	23,135
CAL-N	2	106	1	54
CAL-S	1	101	-	-
Basin	15	5,764	21	8,265
Desert SW	21	7,997	27	10,101
RMPA	23	4,058	27	6,694
NWPP	9	4,277	10	4,384
TOTAL	**576**	**234,371**	**677**	**257,633**

Constricted compliance deadlines may challenge the electric industry's planning horizons, existing planning processes and typical construction schedules. Successful implementation of environmental regulations will be highly dependent on the ability of units needed for reliability to obtain the necessary time needed to comply with certain requirements. Given the timelines for compliance, many of the affected units may need to take maintenance outages concurrently. The need to take multiple units out-of-service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns during maintenance periods.

Reliability Assessment

Sufficient Planning Reserve Margins must be maintained to provide reliable electric service. With fewer resources, flexibility is reduced and the risk of a capacity shortage may increase. Where Planning Reserve Margins fall below zero there is a basic inability to serve load with projected resources.

Resources from these ten-year projections are reduced to form the scenario cases (Moderate Case and Strict Case—previously described in the report) and the resulting Planning Reserve Margins are calculated. This update includes a comparison of the impacts on Planning Reserve Margin for the years 2013, 2015, and 2018 based on the *2011 Long-Term Reliability Assessment* reference case. The resulting Planning Reserve Margin is compared to the NERC Reference Margin Level to determine if more resources may be needed. For the resource adequacy assessment, NERC chose a range of resource categories to evaluate Planning Reserve Margins for these scenarios. The range includes Anticipated Capacity Resources on the low-end and Adjusted Potential Capacity Resources on the high-end.[140]

Overall, impacts on Planning Reserve Margins and the need for more resources is a function of the compliance timeline associated with the potential EPA regulations. Up to a 61 GW reduction of incremental coal, oil, and gas-fired generation capacity is identified as economically vulnerable for retirement during the scenario timeframe. Absent sufficient industry response, the reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the Assessment Areas in the 2018 Strict Case. Potentially significant reductions in capacity by 2015 may require heightened concentration towards the addition of resources; however, for 2015, in a majority of the Assessment Areas, retirements do not appear to significantly impact Planning Reserve Margins. Rather, the need for retrofits and installation of environmental controls by that year is the primary concern.

Additionally, more transmission may be needed as the industry responds to resolve identified capacity deficiencies. As replacement generation is constructed, new transmission may be needed to interconnect new generation. Additionally, existing generation that may not be deliverable due to transmission limitations may need enhancements to the transmission system in order to allow firm and reliable transmission service. While NERC did not model deliverability, operational or stability impacts to the transmission system in this assessment, constructing new transmission or refurbishing existing transmission may be required. These effects on local reliability can create additional timing challenges. For example, transmission system enhancements and reconfiguration may be necessary in some areas, which may create additional timing issues if transmission facilities take relatively longer to construct than generation.

In this update, NERC did not review the potential impact on scheduled maintenance to account for any retrofit work on existing units. The assumption is that all retrofit work will be accomplished during normal maintenance periods, and the reserves available during those maintenance periods will be sufficient to accommodate the increased retrofit work load. However, this may not be the case as a

[140] Refer to the *Terms Used in This Report* section for detailed definitions regarding supply/resource categories.

significant industry-wide retrofit effort over the course of a short timeframe could add unforeseen stresses.

The resource adequacy assessment results are highlights by Assessment Area in Table 37 through Table 45. Planning Reserve Margins impacts are illustrated in Figure 67 through Figure 72.

Note: For the WECC, individual Assessment Area capacity reductions were aggregated to calculate the WECC US Planning Reserve Margin.

Resource Adequacy Assessment Results: 2013

Table 37: 2013 Reference Case

	Total Internal Demand (MW)	Anticipated Capacity (MW)	Adjusted Potential (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	NERC Reference Margin Level (%)
United States						
ERCOT	67,362	76,635	78,671	13.8%	16.8%	13.8%
FRCC	47,446	58,205	58,401	22.7%	23.1%	15.0%
MISO	94,834	114,509	131,651	20.7%	38.8%	15.0%
MRO-MAPP	5,331	7,016	7,016	31.6%	31.6%	15.0%
NPCC-New England	28,525	33,361	37,726	17.0%	32.3%	15.0%
NPCC-New York	33,433	45,814	45,960	37.0%	37.5%	15.5%
PJM	162,489	200,244	203,310	23.2%	25.1%	15.0%
SERC-E	44,863	56,526	56,526	26.0%	26.0%	15.0%
SERC-N	47,359	61,080	61,605	29.0%	30.1%	15.0%
SERC-SE	51,649	63,638	66,668	23.2%	29.1%	15.0%
SERC-W	25,912	34,589	40,882	33.5%	57.8%	15.0%
SPP	55,149	69,226	73,665	25.5%	33.6%	13.6%
WECC US	144,881	200,779	202,109	38.6%	39.5%	14.2%
Total	**809,235**	**1,021,622**	**1,064,190**	**26.2%**	**31.5%**	**15.0%**

Table 38: 2013 Moderate Case Results

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	-	76,635	78,671	13.8%	16.8%
FRCC	-	58,205	58,401	22.7%	23.1%
MISO	-	114,509	131,651	20.7%	38.8%
MRO-MAPP	-	7,016	7,016	31.6%	31.6%
NPCC-New England	-	33,361	37,726	17.0%	32.3%
NPCC-New York	-	45,814	45,960	37.0%	37.5%
PJM	-	200,244	203,310	23.2%	25.1%
SERC-E	-	56,526	56,526	26.0%	26.0%
SERC-N	-	61,080	61,605	29.0%	30.1%
SERC-SE	-	63,638	66,668	23.2%	29.1%
SERC-W	-	34,589	40,882	33.5%	57.8%
SPP	-	69,226	73,665	25.5%	33.6%
WECC US	-	200,779	202,109	38.6%	39.5%
Total	**-**	**1,021,622**	**1,064,190**	**26.2%**	**31.5%**

Table 39: 2013 Strict Case Results

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	76	76,559	78,595	13.7%	16.7%
FRCC	13	58,192	58,388	22.6%	23.1%
MISO	2,066	112,443	129,585	18.6%	36.6%
MRO-MAPP	0	7,016	7,016	31.6%	31.6%
NPCC-New England	0	33,361	37,726	17.0%	32.3%
NPCC-New York	12	45,802	45,948	37.0%	37.4%
PJM	3,398	196,846	199,912	21.1%	23.0%
SERC-E	1,032	55,494	55,494	23.7%	23.7%
SERC-N	325	60,755	61,280	28.3%	29.4%
SERC-SE	1,626	62,012	65,042	20.1%	25.9%
SERC-W	175	34,414	40,707	32.8%	57.1%
SPP	1,067	68,159	72,598	23.6%	31.6%
WECC US	0	200,779	202,109	38.6%	39.5%
Total	**9,791**	**1,011,831**	**1,054,399**	**25.0%**	**30.3%**

Figure 67: 2013 Peak Anticipated Reserve Margin Scenario Impacts

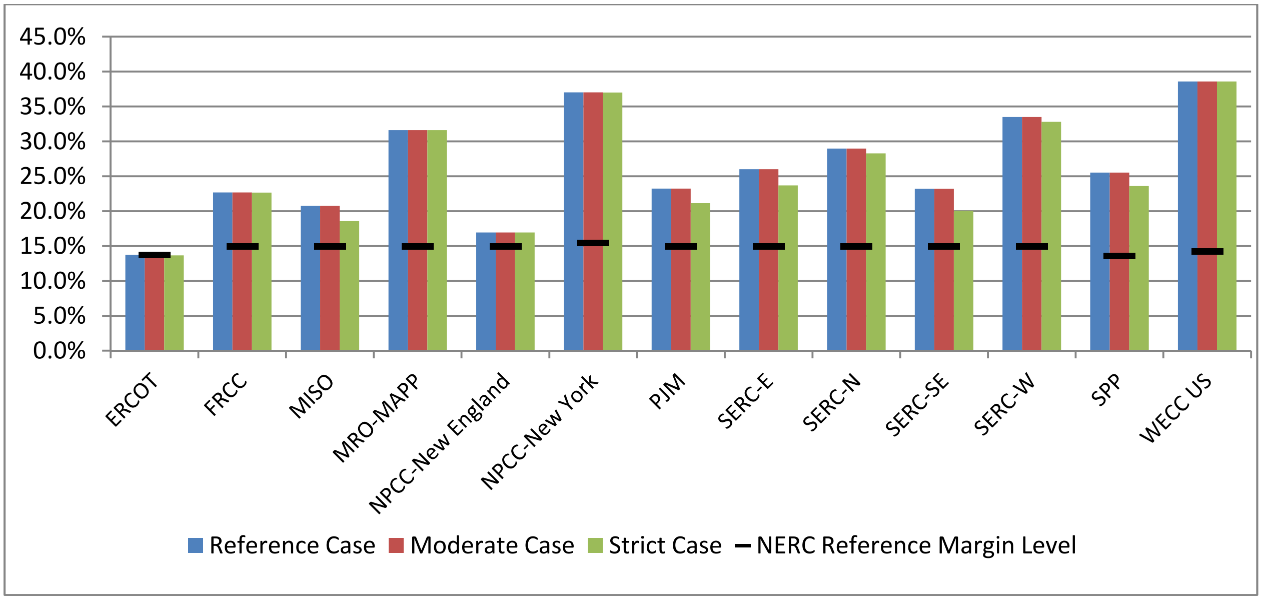
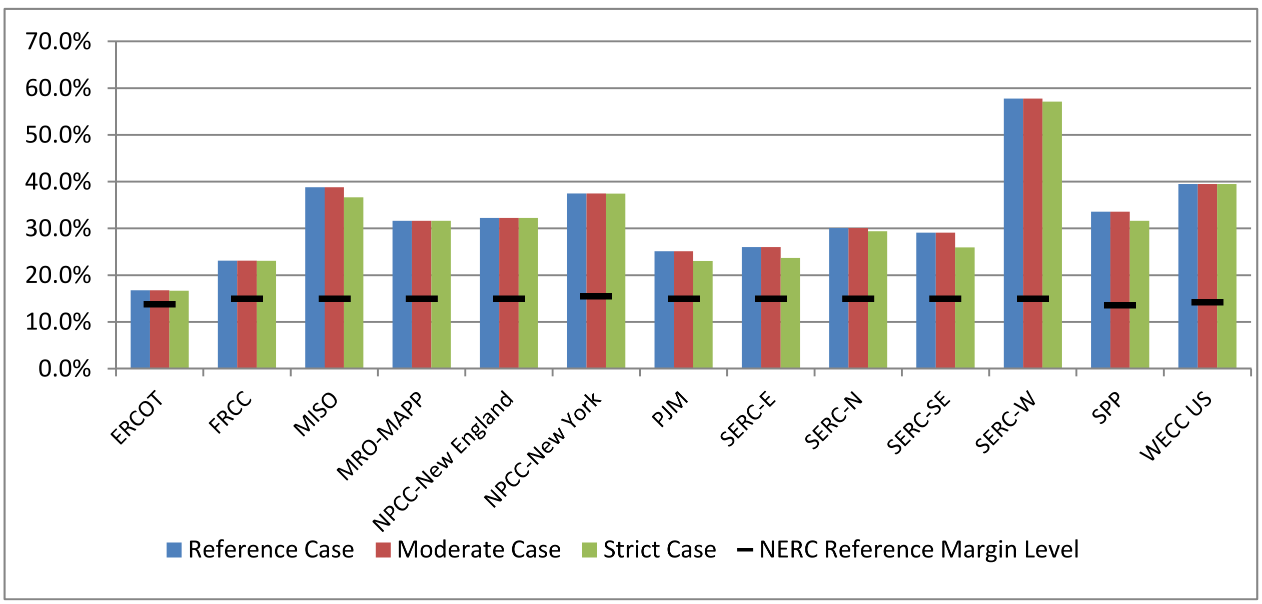


Figure 68: 2013 Peak Adjusted Potential Reserve Margin Scenario Impacts



Resource Adequacy Assessment Results: 2015

Table 40: 2015 Reference Case

	Total Internal Demand (MW)	Anticipated Capacity (MW)	Adjusted Potential (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	NERC Reference Margin Level (%)
United States						
ERCOT	71,910	79,682	82,575	10.8%	14.8%	13.8%
FRCC	49,278	60,761	61,288	23.3%	24.4%	15.0%
MISO	95,947	114,551	131,693	19.4%	37.3%	15.0%
MRO-MAPP	5,497	7,065	7,065	28.5%	28.5%	15.0%
NPCC-New England	29,380	32,886	36,936	11.9%	25.7%	15.0%
NPCC-New York	33,678	46,819	47,052	39.0%	39.7%	15.5%
PJM	166,506	200,990	206,142	20.7%	23.8%	15.0%
SERC-E	46,067	55,023	55,023	19.4%	19.4%	15.0%
SERC-N	48,437	58,570	59,133	20.9%	22.1%	15.0%
SERC-SE	53,378	64,256	67,342	20.4%	26.2%	15.0%
SERC-W	26,806	33,814	41,110	26.1%	53.4%	15.0%
SPP	55,556	69,176	73,834	24.5%	32.9%	13.6%
WECC US	149,723	205,844	209,719	37.5%	40.1%	14.2%
Total	**832,163**	**1,029,437**	**1,078,912**	**23.7%**	**29.7%**	**15.0%**

Table 41: 2015 Moderate Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	267	79,415	82,308	10.4%	14.5%
FRCC	176	60,585	61,112	22.9%	24.0%
MISO	1,629	112,922	130,064	17.7%	35.6%
MRO-MAPP	8	7,057	7,057	28.4%	28.4%
NPCC-New England	237	32,649	36,699	11.1%	24.9%
NPCC-New York	151	46,668	46,901	38.6%	39.3%
PJM	3,456	197,534	202,686	18.6%	21.7%
SERC-E	918	54,105	54,105	17.4%	17.4%
SERC-N	899	57,671	58,234	19.1%	20.2%
SERC-SE	1,675	62,581	65,667	17.2%	23.0%
SERC-W	95	33,719	41,015	25.8%	53.0%
SPP	385	68,791	73,448	23.8%	32.2%
WECC US	364	205,480	209,355	37.2%	39.8%
Total	**10,261**	**1,019,176**	**1,068,651**	**22.5%**	**28.4%**

Table 42: 2015 Strict Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	267	79,415	82,308	10.4%	14.5%
FRCC	1,748	59,013	59,540	19.8%	20.8%
MISO	4,982	109,569	126,711	14.2%	32.1%
MRO-MAPP	10	7,055	7,055	28.3%	28.3%
NPCC-New England	327	32,559	36,609	10.8%	24.6%
NPCC-New York	151	46,668	46,901	38.6%	39.3%
PJM	7,048	193,942	199,094	16.5%	19.6%
SERC-E	1,248	53,775	53,775	16.7%	16.7%
SERC-N	2,125	56,445	57,008	16.5%	17.7%
SERC-SE	3,206	61,050	64,136	14.4%	20.2%
SERC-W	360	33,454	40,750	24.8%	52.0%
SPP	700	68,476	73,134	23.3%	31.6%
WECC US	668	205,176	209,051	37.0%	39.6%
Total	**22,840**	**1,006,597**	**1,056,072**	**21.0%**	**26.9%**

Figure 69: 2015 Peak Anticipated Reserve Margin Scenario Impacts

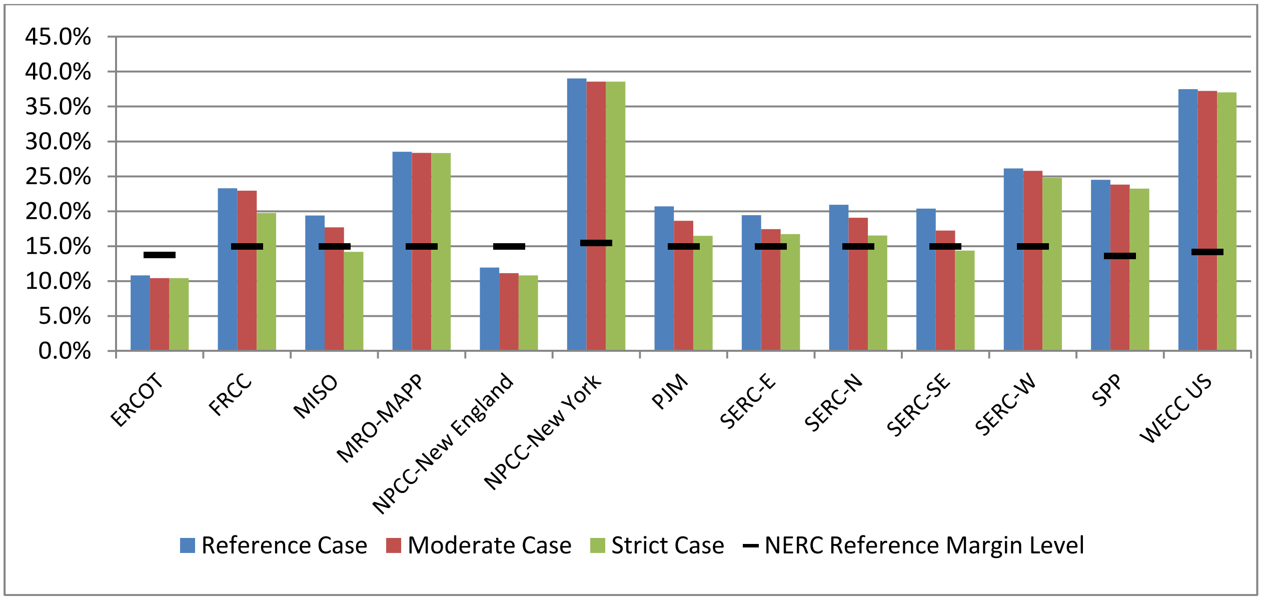
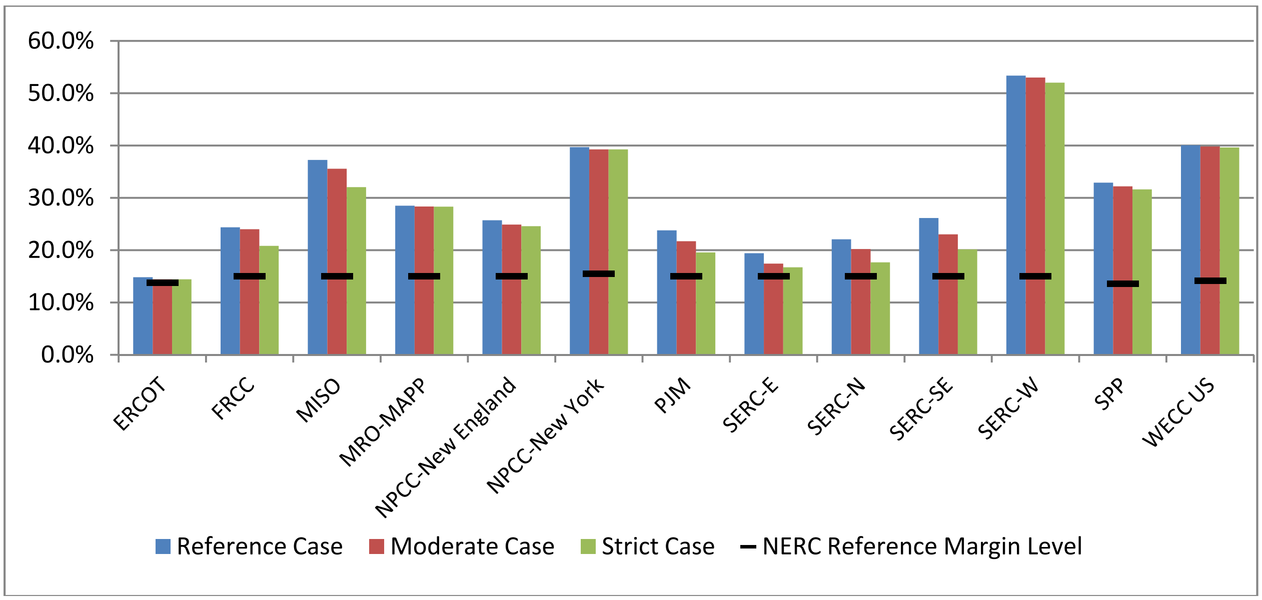


Figure 70: 2015 Peak Adjusted Potential Reserve Margin Scenario Impacts



Resource Adequacy Assessment Results: 2018

Table 43: 2018 Reference Case

	Total Internal Demand (MW)	Anticipated Capacity (MW)	Adjusted Potential (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	NERC Reference Margin Level (%)
United States						
ERCOT	75,521	81,786	85,444	8.3%	13.1%	13.8%
FRCC	51,377	61,286	61,853	19.3%	20.4%	15.0%
MISO	98,110	114,633	131,775	16.8%	34.3%	15.0%
MRO-MAPP	5,776	7,211	7,211	24.8%	24.8%	15.0%
NPCC-New England	30,525	32,639	36,933	6.9%	21.0%	15.0%
NPCC-New York	34,190	46,819	47,073	36.9%	37.7%	15.5%
PJM	171,067	200,990	206,392	17.5%	20.6%	15.0%
SERC-E	47,636	56,104	56,104	17.8%	17.8%	15.0%
SERC-N	50,162	57,010	57,952	13.7%	15.5%	15.0%
SERC-SE	55,592	68,693	71,779	23.6%	29.1%	15.0%
SERC-W	27,806	31,491	40,751	13.3%	46.6%	15.0%
SPP	57,682	71,654	77,028	24.2%	33.5%	13.6%
WECC US	157,408	209,508	216,792	33.1%	37.7%	14.2%
Total	**862,851**	**1,039,825**	**1,097,086**	**20.5%**	**27.1%**	**15.0%**

Table 44: 2018 Moderate Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	5,451	76,335	79,993	1.1%	5.9%
FRCC	1,107	60,179	60,746	17.1%	18.2%
MISO	1,629	113,004	130,146	15.2%	32.7%
MRO-MAPP	8	7,203	7,203	24.7%	24.7%
NPCC-New England	5,138	27,501	31,795	-9.9%	4.2%
NPCC-New York	4,448	42,371	42,625	23.9%	24.7%
PJM	4,359	196,631	202,033	14.9%	18.1%
SERC-E	918	55,186	55,186	15.9%	15.9%
SERC-N	899	56,111	57,053	11.9%	13.7%
SERC-SE	1,912	66,781	69,867	20.1%	25.7%
SERC-W	95	31,396	40,656	12.9%	46.2%
SPP	385	71,269	76,643	23.6%	32.9%
WECC US	9,412	200,096	207,380	27.1%	31.7%
Total	**35,761**	**1,004,064**	**1,061,325**	**16.4%**	**23.0%**

Table 45: 2018 Strict Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	5,965	75,821	79,479	0.4%	5.2%
FRCC	2,679	58,607	59,174	14.1%	15.2%
MISO	5,406	109,227	126,369	11.3%	28.8%
MRO-MAPP	10	7,201	7,201	24.7%	24.7%
NPCC-New England	5,342	27,297	31,591	-10.6%	3.5%
NPCC-New York	4,637	42,182	42,436	23.4%	24.1%
PJM	10,682	190,308	195,710	11.2%	14.4%
SERC-E	1,332	54,772	54,772	15.0%	15.0%
SERC-N	2,125	54,885	55,827	9.4%	11.3%
SERC-SE	3,555	65,138	68,224	17.2%	22.7%
SERC-W	3,684	27,807	37,067	0.0%	33.3%
SPP	3,251	68,403	73,777	18.6%	27.9%
WECC US	10,489	199,019	206,303	26.4%	31.1%
Total	**59,157**	**980,668**	**1,037,929**	**13.7%**	**20.3%**

Figure 71: 2018 Peak Anticipated Reserve Margin Scenario Impacts

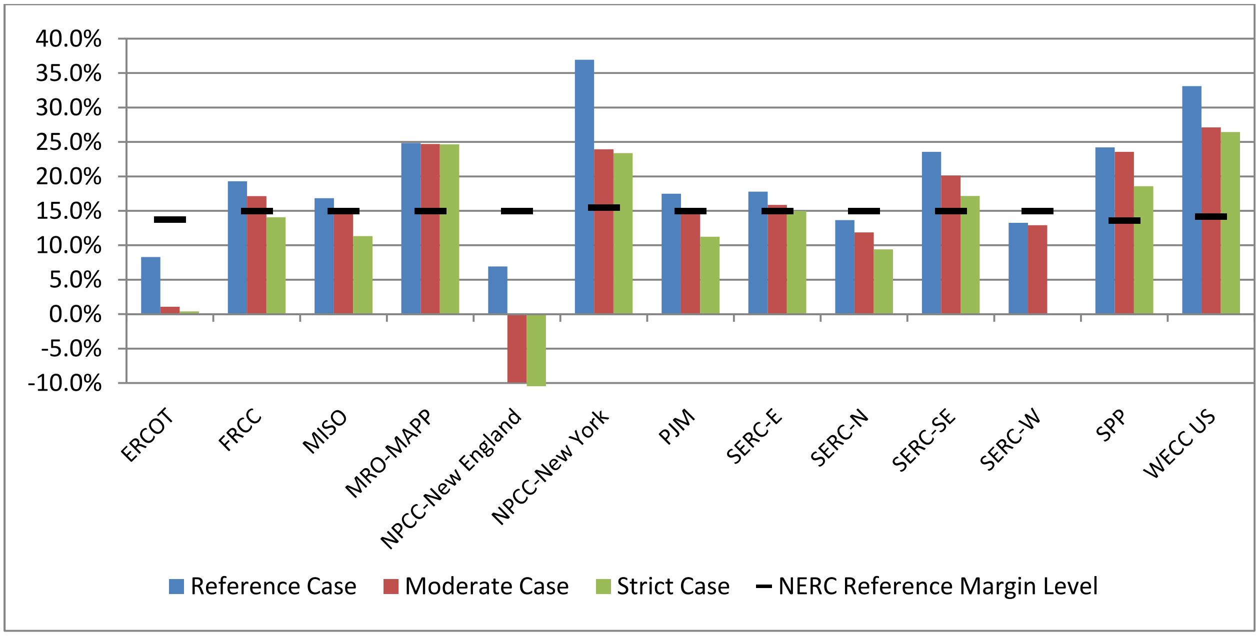
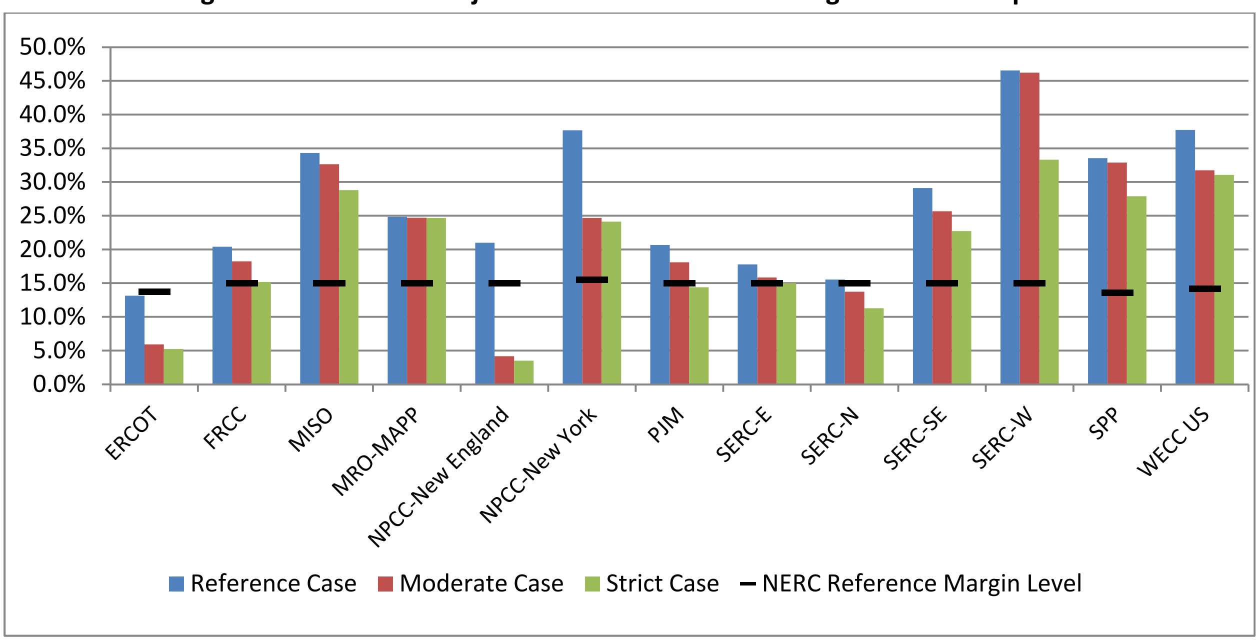


Figure 72: 2018 Peak Adjusted Potential Reserve Margin Scenario Impacts



Regional Assessment

For this update, NERC requested additional information from the Regional Entities. The Regions were requested to provide an update to NERC detailing the potential impacts caused by potential environmental regulations, identify the methods used to assess these impacts, and provide results of individual studies, if studies have been performed. Additionally, the Regional Entities identified potential issues unique to their area, measures in place, or being considered for implementation, to mitigate potential reliability concerns, and outline future activities planned to understand potential reliability impacts within the Region. The individual assessments are provided in the following sections. These regional assessments are not based on NERC's modeling results provided in this update, but instead, are summaries of their own assumptions and studies developed by each Regional Entity.

ERCOT

Potential or pending environmental regulations are studied, as they occur or are proposed, to determine the potential impact on system reliability. Regulations that could challenge the economic or operational viability of a generation resource are studied to determine the likelihood of that regulation to create resource adequacy issues within the ERCOT Region. For example, should a particular environmental regulation restrain or restrict coal-fired generating stations, ERCOT would perform an economic and transmission system study to determine the reliability implications to ERCOT given the proposed limitations to an existing resource or group of resources. One such study[141] has recently been completed to determine the reliability implications of the Clean Water Act (Section 316(b), Title I of the Clean Air Act (new emissions standards for hazardous air pollutants), Clean Air Transport Rule (CATR), and Coal Combustion Residuals (CCR) Disposal Regulations. A preliminary analysis of localized transmission system impacts included in the study indicates that the potential loss of 9,800 MWs of gas-fired generation would have impacts on transmission reliability in certain load center regions, likely requiring additional reactive devices and new import pathways into those regions. Redevelopment of existing generation sites in these areas with new generating units could reduce or delay the need for additional transmission infrastructure. In addition, ERCOT recently completed an assessment[142] of the proposed inclusion of Texas in the Cross-State Air Pollution Rule (replaces CATR). The assessment found that, if the rule is implemented as currently scheduled on January 1, 2012, then generators' current compliance plans indicate that 1,200 to 1,400 MW of generation would be unavailable year round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months. The unavailability of this generation would increase capacity insufficiency and the potential need for emergency actions including rotating outages, not only during the peak months but also during the off-peak months until retrofits or alternative resources are implemented.

FRCC

Entities may face challenges in scheduling the required overlapping maintenance outages of fossil-fired generating units. Resource adequacy in the near-term could also potentially be affected due to the lack of materials needed to retrofit existing resources. In addition, operational impacts associated with changes in dispatch patterns under certain conditions may occur. In order to address these concerns,

[141] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf
[142] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf

entities within the FRCC Region are closely monitoring legislation related to EPA initiatives and evaluating potential options.

MRO

Recent environmental EPA rule proposals and the uncertainty around carbon control challenge industry's ability to finalize their plans. Ultimately, they could impact the configuration and operation of the bulk power system. These impacts may result in retirements of generation within the MRO-MISO footprint. If this occurs, the system within MRO-MISO may experience reliability impacts from the generation and transmission perspective.

To maintain compliance with environmental rules, capacity will be reduced from the system associated with both retrofits and retirements. In the MRO-MISO footprint, this will reduce the amount of existing capacity available to meet resource adequacy requirements. Transmission adequacy could also be impacted depending on what units retire from the bulk power system as a result of the rules. For example, a unit needed for transmission reliability and voltage support in a metro area may require additional transmission support to meet the reliability requirements on the system.

The current proposed rules will impact the coal-fired generation fleet located throughout the MRO-MISO footprint. From internal rule evaluation, the units most likely targeted for retirement are expected to be small, old units. However, all units that do not meet the proposed rule requirements will be impacted through retrofit costs and operational impacts of the new equipment. Carbon reduction requirements could put additional pressure on the coal-fired fleet in the MRO-MISO footprint and result in additional retirements. In fact, the uncertainty around future carbon reduction requirements may result in accelerated unit retirements rather than retrofit to reduce future cost risks.

Up to this point, the final and proposed EPA rules and the uncertainty around carbon reduction has not resulted in any current reliability issues. MRO and MISO are evaluating the potential impacts to be prepared to meet the stakeholders' needs as they determine whether units are to retire or retrofit. This will include evaluating impacts on resource and transmission adequacy. A proposed new capacity construct within MISO will also provide additional mitigation of reduced capacity on the system by allowing better management and integration of demand side resources and the management of the participation of intermittent resources.

NPCC

New England: ISO-NE routinely reviews the existing, pending, and promulgating environmental regulation for their potential impacts on existing or future capacity. Under the workloads associated with its Strategic Planning Initiative, ISO-NE has identified several regional power stations that may be retired due to the economics of compliance with pending state and Federal air and water regulations.

Emerging environmental regulations will very likely require large capital investments that are uneconomic for many older fossil-fueled resources. While the exact form and timing of the requirements remain uncertain, the stated intent of and requirements on the U.S. Environmental

Protection Agency (in certain instances through court order) means that there is a very high likelihood that substantial compliance investments will be required by owners of existing New England resources to continue operations. This could lead to a significant quantity of older generation choosing to retire rather than comply.

Compliance with a wide range of environmental requirements is expected to trigger capital investments beginning as soon as within the next two years and extending out for several years. Consequently, decisions on resource retirement and capacity pricing in light of these emerging requirements may affect current capacity auctions.

Currently, procedures are in place that would maintain system reliability. These include reliability agreements and out-of-merit unit commitment. However, appropriate enhancements to wholesale market design and system planning procedures could reduce the need for reliability agreements and out-of-merit unit commitment and dispatch, which would degrade the efficiency of market operations and/or prompt regulatory action. In addition, losing a significant quantity of coal, oil and nuclear capacity could further increase the areas dependence on natural gas-fired resources. The retirement of a significant quantity of capacity will almost certainly trigger a vigorous debate on whether to solve the resulting reliability problems with market resources or transmission. If all of the area's older oil units were to seek retirement, new capacity resources would be required to satisfy the Installed Capacity Requirement.

ISO-NE has initiated and is aggressively promoting a regional dialogue focused on solutions that can avert undesirable outcomes. ISO-NE has initiated a study to better quantify the implications of this issue. This analysis will complement the 2010 economic planning studies.

New York: Environmental initiatives that may affect generation resources may be driven by either or both the State and Federal programs. The 2009 New York State Energy Plan provides a long range vision and framework for New York's energy usage. The State's Department of Environmental Conservation (NYS DEC) annual publication of its regulatory agenda describes the new environmental initiatives that it will focus on during the coming year. The U.S. Environmental Protection Agency also publishes a similar report on its regulatory agenda.

There are numerous environmental initiatives that may impact the manner in which the existing generating fleet operates or require retrofitting environmental control technologies in order to comply with the new requirements. Several proposals have been identified for which impacts are expected to be widespread and likely to require significant capital investments in order to achieve the new standards.

RFC

Both PJM and MISO are independently reviewing the impacts of potential retirements within their RTOs. This assessment, which has been completed by Reliability*First* staff, reviews the moderate and Strict Cases for all four EPA regulations at the same time. Regional resource adequacy within Reliability*First* is determined by assessing the resource adequacy of each RTO, and this regional retirement scenario determines the reserve margin impact of each RTO.

PJM and MISO are the RTOs that operate within the Reliability*First* footprint. Both stakeholders (PJM and MISO) have processes in place to review the reliability impacts of planned retirements prior to the scheduled retirement date. Each planned retirement is reviewed for any potential reliability issues, and any issues must first be mitigated before the planned retirement can occur. Since most generation owners do not announce their intent to retire a generating unit before it is necessary to get the RTO review, only a small number of units have been identified for future retirement through the PJM and MISO processes. In previous Long Term Reliability Assessments, the amount of unit retirements included in the assessment has been low.

Based on the data in this retirement assessment, PJM and MISO are projected to need additional resources or demand response by 2019 and 2018, respectively, under the moderate assumptions case. For the strict assumptions case, additional resources or demand response will be need as early as 2015 by MISO and in 2017 by PJM. The amount of retirements in this assessment, while exceeding recent experience, is a reasonable representation of the range of potential future generation retirements given the scope of the NERC special assessment and compliance to new EPA regulations. The amount of uncertainty in demand forecasts, future capacity additions and future generation retirements becomes greater with each additional year of the projected forecast. The inherent uncertainties in forecasting future reserve margins means that future retirement plans need to be more closely monitored in order to assess whether future reserve margin targets can be satisfied.

Recently, AEP has announced plans to retire nearly 6,000 MW of existing capacity to comply with these proposed regulations. Many of the proposed AEP capacity retirements are included in this future retirement assessment. As much as 1,900 MW of capacity identified by AEP as retirement candidates, were considered retrofitted in the NERC special assessment. The AEP announcement also indicated the repowering of several retired coal units with natural gas. This would effectively replace an additional 600 MW. The analysis in this assessment does not include any additional future capacity additions or repowering beyond what was already listed in the PJM and MISO generator interconnection queues. Modifying the PJM retirement assessment data for the AEP projected changes would reduce generation an additional 1,300 MW within PJM in the Moderate Case and 800 MW in the Strict Case. When these are added to those in the retirement scenario, PJM may need additional resources one year earlier.

SERC

Entities within SERC are currently in the process of evaluating the potential impacts of the Cross-State Air Pollution Rule (CSAPR) to meet the compliance obligations that begin January 1, 2012. The short timeframe to comply is a concern amongst entities, as there is the possibility of significant reductions in capacity factors for some generating units, which will require Must Run operations under certain system conditions. Implementation of CSAPR in 2012 will restrict dispatch flexibility, reducing options for addressing reliability challenges during adverse operating conditions such as weather extremes and significant unplanned events. The Utility MACT Rule that EPA plans to issue in December 2011, will initiate a three year implementation period requiring an aggressive construction schedule in SERC to install transmission reinforcements, generation additions, and environmental controls retrofits. Transmission and generation outage coordination will be significantly challenged. CSAPR limits in interstate allowance trading may also impact the ability to obtain assistance from neighboring areas.

With Utility MACT compliance requirements in 2015, severe reductions in capacity could result depending upon the levels of environmental controls required by the final rule and the ability of entities to retire/replace generation and install controls within the 3 year compliance deadline. In many areas of SERC, utilities are working internally and with consultants to gain a better understanding of the EPA rules and to assess the costs and scheduling of implementing various pollution control measures or generation alternatives. Efforts are ongoing at this time as entities strive to develop strategies to comply based upon the thresholds provided in EPA's proposed rules. However, these strategies will not be finalized until future regulations are released.

The data below represents additional information collected in August 2011, as requested by NERC. Fluctuations in capacity reflect the changes that entities have made for the 2011 annual peak data reported from February to September 2011. Announced retirements and station loads due to retrofits are reflected in the values of the SERC 2011 Long-Term Reliability Assessment reference case. However, many generation retirement decisions will not be made until the final Utility MACT rules have been issued and assessed. These uncertain retirement decisions are not included in the 2011 reference case because resource plans typically reflect only existing rules and regulations and do not include resource impacts related to potential requirements.

Flue Gas Desulfurization Scrubbers (FGD) and Select Catalytic Reduction (SCR) controls have already been installed on many units to address emission concerns. Recent SERC entities' responses indicate that approximately 129 units have been retrofitted with FGDs and/or SCRs to comply with EPA regulations. It was reported that 24 retrofit projects are underway or awaiting regulatory approval. Of these projects, 5 (1,563 MW) are scheduled to be completed by the summer of 2012. More than 52 units (~ 8,000 MW) require additional environmental controls for compliance. Many entities note that these are preliminary projections of the projects needed and will continue to evaluate the remaining uncontrolled units to determine which, if any, of the units will be retrofitted with FGD systems and SCRs. Decisions to retrofit, retire, convert to gas operation, or replace those units will be made when future EPA Regulations' criteria and implementation timelines become more transparent. In many cases, transmission enhancements and gas pipeline infrastructure to support these decisions cannot be accomplished during a three year implementation period.
Depending upon the emissions levels established by the final Utility MACT rules, additional controls (such as baghouses) may need to be added to units that are already equipped with FGDs and SCRs. It is unknown whether units which have already installed FGDs and SCRs would be permitted to operate beyond 2015 if additional required controls, such as baghouses, cannot be completed in time.

Units to be retired within the areas are also uncertain at this time. Initial reports show that approximately 10,250 MW (58 units) of coal-fired generation will be retired within the SERC Region to be compliant with the recent rules. Although entities feel it is very early in the process to determine the impacts of the rules, their analyses consider all current, proposed, and expected rules such as: the Cross-

State Air Pollution Rule (or its predecessors CAIR/the proposed Transport Rule), Clean Air Visibility Rule (CAVR), the proposed Electric Generating Unit Maximum Achievable Control Technology (Utility MACT) rule, the proposed 316(b) rule for cooling water intake structures, the proposed Coal Combustion Residuals (CCR) rule, and expected regulation of Greenhouse Gases (GHGs), along with a range of potential fuel prices. State regulators are also involved in the process to help entities establish plans to replace any capacity that may be lost, and approve retirements and retrofits that are needed. Significant amounts of potential generation capacity retirements have not yet been provided for inclusion in the 2011 Long-Term Reliability Assessment reference case because many state resource plans do not reflect the potential impacts of proposed EPA rules.

Recent SERC entities' analyses shows that approximately 6,200 MW or more of coal- and oil-fired generation is expected to be converted to other fuels, such as natural gas. Some capacity will be permanently retired, whereas other capacity may be unable to operate pending additional environmental controls or gas conversion infrastructure. Consideration of various resource selections in the assessment process may require transmission enhancements and take into account construction schedules. In general, many entities are uncertain of specific sites for additional capacity, if needed, at this time. Ongoing nuclear, demand-side management, biomass and renewable resource projects are also being implemented. New resources and programs would require additional time to design, obtain regulatory approval, implement and gain reasonable scale.

SERC entities are also assessing operational reliability impacts related to changes in the generation fleet makeup and operating parameters. These reliability assessments include revisions to System Restoration Plans (Blackstart), gas pipeline contingency studies, multiple unit outage contingencies related to common environmental controls, stability and voltage security impacts, fault current studies, and others.

Entities within SERC are taking various steps to assess the impacts of the EPA rules. Consultants have been hired to assess entity costs, studies are in progress to develop plans for generation redispatch, and operational procedures are being revised to compensate for alternative generation mixes. These tasks reflect SERC entity efforts to find strategies to achieve the lowest reasonable operational cost consistent with the provision of adequate and reliable electric service, while complying with environmental regulations. Entities are concerned that the timeframe to become compliant with the new rules is not sufficient to complete the many retrofit projects needed on existing units. Some deem the impact of these new rules will jeopardize reliability because: 1) units without all of the required environmental control retrofits may not be allowed to operate, 2) replacement generation or infrastructure upgrades for fuel switches may not be complete, and 3) final decisions regarding whether to retrofit, retire and replace, or change the fuel supply of units to natural gas will not be made until all the rules are final.

SPP

Due to the EPA's adoption of the CSAPR in July 2011, the SPP RTO and its members have not had time to fully assess the Rule's impacts to individual systems or to the RTO as a whole. The SPP EPA Study did not originally include the final CSAPR impacts, but the SPP RTO began working on a 2012 assessment of the CSAPR in September 2011 (SPP CSAPR Study). The study began with a review of the EPA CSAPR Model results which showed that 10.7 GWs of generating capacity in the SPP RTO footprint would not be deployed in 2012.[143] Further analysis to account for capacity that is not expected to be needed for peak yielded a net impact of CSAPR of 5.4 GWs from 48 units that would be unavailable across the 2012 Summer Peak. Additionally, the SPP CSAPR Study showed a shift in the generation from larger plants to smaller plants. Preliminary results of the SPP CSAPR study show that many overloads greater than 120 percent of a facility's emergency ratings were found under N-1 conditions. Furthermore, due to the non-deployment of major units in some areas there were voltage issues below 85 percent, with two-thirds of the voltage issues occurring on 115kV lines, and the remaining one-third on 69 kV lines. However, the reliability impacts have not yet been fully determined and work continues on the SPP CSAPR Study.[144]

WECC

On May 4, 2010, California's State Water Resources Control Board (SWRCB) adopted a policy regarding once-through cooling used at electricity-producing power plants in California. *Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*[145] provides clear and consistent standards for implementing the Clean Water Act for electricity-producing power plants, which operate under National Pollutant Discharge Elimination System (NPDES) permits issued by California's nine Regional Water Boards. In developing the policy, the State Water Board staff met regularly with representatives from the agencies that oversee the electricity supply grid (including the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator) to develop realistic and phased-in implementation plans and schedules. Under the draft policy, the State Water Board will continue to work with the energy agencies to ensure that the compliance schedules assure electric supply reliability. Information regarding the policy, a proposed policy amendment and the compliance plans filed by the owners of the 19 plants (21,000 MW) is available on the SWRCB website.[146] The current fluid nature of compliance plans combined with long-term plans for California's resource additions has created problematic issues in producing a detailed reliability assessment. Despite these circumstances, WECC staff is currently not aware of planned individual unit retirements that are expected to have a significant impact on reliability.

[143] The EPA Model deployed generating units based on a unit retro-fit analysis instead of on a system reliability basis. EPA CSAPR Model

[144] These results are based on EPA CSAPR Model unit deployments rather than individual SPP Member plans for their generation assets.

[145] http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/alamitos/docs/ags_ip2011.pdf.

[146] SWRCB Once-Through Cooling Information: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

Conclusions

While none of the EPA rules are final, and thus their impact cannot be completely measured, the results of this update show a measurable impact to Planning Reserve Margins should the four potential EPA rules NERC has examined be implemented as assumed in this update. Impacts to both bulk power system planning and operations may cause serious concerns unless prompt industry action is taken. Planning Reserve Margins appear to be impacted in certain Assessment Areas, driving potential resource adequacy concerns. Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort, along with the need to add system reinforcement. The update results along with information provided by NERC stakeholders and industry representatives revolve around five key conclusions:

1. **<u>Timing</u>** – Compliance deadlines will challenge the electric industry's planning horizons, existing planning processes and typical construction schedules. Transmission lines, power plants, and environmental control retrofits are often planned and constructed over a long period of time. Successful implementation of the proposed EPA rules will be highly dependent on the amount of time the industry will be given to comply with future environmental regulations and that tools are in place within a timely manner to support the industry's transition given the large number of units that must be retrofit.

2. **<u>Regionality</u>** – The fuel-mix differs greatly across the country. Each area will face different dynamics due to the types of generators as well as the types of regulatory environments within a given area (*i.e.,* deregulated markets, regulated utility service areas, state regulations). State decisions could greatly influence the cumulative impacts.

3. **<u>Outage Coordination</u>** – Given the window for compliance, many affected units may need to take long-term maintenance outages concurrently. The need to take multiple units out-of-service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns.

4. **<u>Transmission and Operational Issues</u>** – The retirement of larger and/or strategically situated generating units will cause changes to the power flows and stability dynamics of the bulk power system. These changing characteristics will require enhancements to the interconnected transmission systems to provide reactive and voltage support, address thermal constraints, and provide for system stability. Based on information gathered from stakeholders and the Regional

Entities, these issues may cause some reliability concerns unless the transmission system is reconfigured. In some cases, these reliability issues can result in violations of NERC Reliability Standards and, therefore, pose a threat to reliability if they are not addressed.

As more gas-fired generation is incorporated into a given system gas and electric interdependency issues must also be addressed. More gas-fired generation will require additional gas pipeline infrastructure, increased coordination with pipeline operators, and developing operational strategies to minimize potential fuel delivery issues. These issues were highlighted in a recent NERC report on gas and electric interdependencies.

5. **<u>Uncertainty</u>** – A major concern among planning entities and regulatory bodies, such as NERC, is the lack of certainty both on the generating supply side and from EPA. Planning Authorities disconnected from the owning/operating functions of generation do not have the visibility needed to accurately model these potentially significant system changes. For example, rules within the ISO/RTO market structures allow generators to request retirement within 90 days of the requested retirement date. Even with facilities which are not being retired, Planning Authorities and grid operators may not be aware of significant changes in plant operating parameters and new common contingencies. The lack of information and data sharing, and therefore sufficient planning, causes concern.

   Uncertainty remains within the regulatory policy making process as to what the final requirements will be on generators. While many of the rules have been proposed, with some already finalized, the industry is forced to continue to make assumptions on what the final rules will require. While the proposed rules give a good representation, final rules can be quite different (*e.g.,* as seen in Texas/ERCOT). Increasing the certainty with respect to the timing and requirements of the regulations would promote timely and sound engineering planning to support the implementation of these rules in an orderly and predictable manner.

   Furthermore, as rules are finalized and more flexibility is needed to reliably operate the bulk power system, an efficient and systematic process is needed to grant waivers and extensions for generators that are vital to the grid (*i.e.,* critical reliability units, black-start).

KEY FINDINGS - ENVIRONMENTAL REGULATIONS

Existing and proposed environmental regulations in the U.S. may significantly affect bulk power system reliability depending on the scope and timing of the rule implementation and the mechanisms in place to preserve reliability.

Recommendations

The following recommendations are pertinent to Federal and state regulators, the electric industry, as well as NERC, and supplement the 2010 NERC EPA Assessment:

Regulators:

- The Electric Reliability Organization's Reliability Standards and Regional Criteria must be met at all times to ensure reliable operation and planning of the bulk power system. Based on the results of this study, more time is needed in certain areas to ensure resource adequacy and local reliability requirements can be addressed during the transition period. EPA, FERC, DOE and state utility regulators, working together and separately, should employ the array of tools at their disposal and their regulatory authority to preserve bulk power system reliability, including the deferral of compliance targets and granting extensions where there is a demonstrated reliability need. Coordination among Federal agencies is necessary to ensure the industry is not forced to violate one regulation to meet another.

Industry:

- Industry participants must meet NERC's Reliability Standards to ensure reliability and as they address compliance requirements of the EPA regulations. They should employ available tools and processes to ensure that bulk power system reliability is maintained through any resource transition. Toward that end, regional wholesale competitive market operators should ensure capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in areas without organized markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations. Additionally, affected unit owners that may be disconnected from wide-area planning functions (*e.g.,* generator owners operating in an ISO/RTO), should provide Planning Authorities timely and accurate information about the compliance plans for their units in order to adequately measure.

- Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed environmental control equipment. Outages for retrofits, new generation, and required transmission must be coordinated to ensure continued bulk power system reliability not only during peak periods, but during off-peak shoulder months when more scheduled outages are expected to occur.

NERC:

- NERC should continue to assess the implications of the EPA regulations as greater certainty emerges around industry obligations, technologies, timelines, and targets. Further, NERC should lead industry's effort and response to measure resource adequacy implications along with impacts to operating reliability (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) resulting from proposed and pending EPA regulations. NERC should leverage the expertise of the Planning Authorities to assess the local system conditions that could degrade reliability, review plans for meeting environmental regulations as well as NERC Reliability Standards, and submit recommendations to FERC on behalf of the industry.

Additional Background Information

Table 46: Projected Incremental Capacity Losses through 2013 by Regulation – Moderate Case

	Moderate Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 47: Projected Incremental Capacity Losses through 2013 by Regulation – Strict Case

	Strict Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	-	-	-	-	67	-	-	-	76
FRCC	-	-	-	-	-	8	-	-	-	13
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	12
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	851	212	-	-	1,679	387
PJM	-	-	-	-	1,487	81	-	-	3,173	225
SERC-N	-	-	-	-	65	44	-	-	264	61
SERC-W	-	-	-	-	-	57	-	-	75	100
SERC-SE	-	-	-	-	157	8	-	-	1,555	72
SERC-E	-	-	-	-	262	-	-	-	1,018	14
SPP	-	-	-	-	26	136	-	-	811	256
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	2,847	612	-	-	8,574	1,217
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 48: Projected Incremental Capacity Losses through 2015 by Regulation – Moderate Case

	Moderate Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	9	-	99	-	267
FRCC	-	77	-	-	-	-	628	65	-	176
ISO-NE	-	32	-	-	-	-	-	22	144	93
NYISO	-	51	-	-	-	-	74	16	74	77
MAPP	-	-	-	-	-	-	-	8	-	8
MISO	-	-	-	-	-	10	1,110	508	1,110	519
PJM	-	8	-	-	-	16	2,650	536	2,850	606
SERC-N	-	-	-	-	-	12	262	168	724	175
SERC-W	-	-	-	-	-	-	-	95	-	95
SERC-SE	10	47	-	-	-	4	699	179	1,358	318
SERC-E	-	-	-	-	-	-	656	112	808	110
SPP	-	-	-	-	-	1	187	197	187	198
CAL-N	-	1	-	-	-	-	15	1	15	4
CAL-S	-	3	-	-	-	-	83	1	83	4
Basin	-	-	-	-	-	-	39	29	39	29
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	-	-	-	-	-	-	99	23	89	23
NWPP	-	-	-	-	-	-	12	34	12	34
TOTAL	10	377	-	-	-	53	6,513	2,127	7,491	2,770
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 49: Projected Incremental Capacity Losses through 2015 by Regulation – Strict Case

	Strict Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	50	-	99	-	267
FRCC	-	6	-	-	-	4	1,254	60	1,592	156
ISO-NE	-	-	-	-	-	-	144	19	239	88
NYISO	-	22	-	-	-	9	74	16	74	77
MAPP	-	2	0	-	-	-	-	8	-	10
MISO	44	799	0	-	928	257	1,297	506	3,583	1,400
PJM	5	377	-	-	1,506	168	4,016	513	5,725	1,323
SERC-N	-	214	0	-	65	59	547	164	1,690	435
SERC-W	-	-	-	-	0.02	57	0.02	95	265	95
SERC-SE	10	-	-	-	478	60	1,181	170	2,942	265
SERC-E	-	-	-	-	490	11	903	108	945	303
SPP	-	196	-	-	77	165	187	197	285	415
CAL-N	15	-	-	-	-	-	15	1	67	2
CAL-S	-	-	-	-	-	-	83	1	184	-
Basin	39	6	-	-	-	-	39	29	39	35
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	18	32	-	-	-	-	143	22	203	53
NWPP	-	6	-	-	-	-	12	34	12	40
TOTAL	130	1,817	0.09	-	3,544	841	9,893	2,078	17,844	4,996
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 50: Projected Incremental Capacity Losses through 2018 by Regulation – Moderate Case

	Moderate Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	9	-	99	-	267
FRCC	-	107	-	-	-	-	628	65	-	176
ISO-NE	-	79	-	-	-	-	-	22	144	93
NYISO	74	60	-	-	-	-	74	16	74	77
MAPP	-	-	-	-	-	-	-	8	-	8
MISO	-	-	96	-	-	10	1,110	508	1,110	519
PJM	209	67	-	-	-	16	2,650	536	2,850	606
SERC-N	-	-	135	-	-	12	262	168	724	175
SERC-W	-	-	-	-	-	-	-	95		95
SERC-SE	10	179	-	-	-	4	699	179	1,358	318
SERC-E	-	-	-	-	-	-	656	112	808	110
SPP	-	-	-	-	-	1	187	197	187	198
CAL-N	15	3	-	-	-	-	15	1	15	4
CAL-S	83	3	-	-	-	-	83	1	83	4
Basin	-	-	-	-	-	-	39	29	39	29
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	-	-	-	-	-	-	99	23	89	23
NWPP	-	-	-	-	-	-	12	34	12	34
TOTAL	390	657	231	-	-	53	6,513	2,127	7,491	2,770
Oil/Gas-Steam Turbine Units										
ERCOT	5,065	119	-	-	-	-	-	-	5,065	119
FRCC	904	27	-	-	-	-	-	-	904	27
ISO-NE	4,898	4	-	-	-	-	-	-	4,898	4
NYISO	4,096	201	-	-	-	-	-	-	4,096	201
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	903	-	-	-	-	-	-	-	903	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	237	-	-	-	-	-	-	-	237	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	2,138	-	-	-	-	-	-	-	2,138	-
CAL-S	6,439	48	-	-	-	-	-	-	6,439	48
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	418	5	-	-	-	-	-	-	418	5
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	25,097	404	-	-	-	-	-	-	25,097	404

Table 51: Projected Incremental Capacity Losses through 2018 by Regulation – Strict Case

	Strict Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	50	-	99	-	267
FRCC	-	107	628	-	-	4	1,254	60	1,592	156
ISO-NE	-	79	-	-	-	-	144	19	239	88
NYISO	74	60	-	-	-	9	74	16	74	77
MAPP	-	2	-	-	-	-	-	8	-	10
MISO	714	987	109	-	928	257	1,297	506	3,583	1,400
PJM	1,334	949	-	-	1,506	168	4,016	513	5,725	1,323
SERC-N	200	308	135	-	65	59	547	164	1,690	435
SERC-W	-	11	-	-	-	57	-	95	265	95
SERC-SE	120	176	120	-	478	60	1,181	170	2,942	265
SERC-E	143	204	-	-	490	11	903	108	945	303
SPP	74	216	51	-	77	165	187	197	285	415
CAL-N	15	3	-	-	-	-	15	1	67	2
CAL-S	83	3	-	-	-	-	83	1	184	-
Basin	39	6	-	-	-	-	39	29	39	35
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	43	33	-	-	-	-	143	22	203	53
NWPP	12	6	-	-	-	-	12	34	12	40
TOTAL	2,850	3,308	1,043	-	3,544	841	9,893	2,078	17,844	4,996
Oil/Gas-Steam Turbine Units										
ERCOT	5,593	105	-	-	-	-	-	-	5,593	105
FRCC	904	27	-	-	-	-	-	-	904	27
ISO-NE	5,015	-	-	-	-	-	-	-	5,015	-
NYISO	4,291	195	-	-	-	-	-	-	4,291	195
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	424	-	-	-	-	-	-	-	424	-
PJM	3,632	2	-	-	-	-	-	-	3,632	2
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	3,134	190	-	-	-	-	-	-	3,134	190
SERC-SE	349	-	-	-	-	-	-	-	349	-
SERC-E	84	-	-	-	-	-	-	-	84	-
SPP	2,523	29	-	-	-	-	-	-	2,523	29
CAL-N	2,138	-	-	-	-	-	-	-	2,138	-
CAL-S	6,924	36	-	-	-	-	-	-	6,924	36
Basin	113	-	-	-	-	1	-	-	113	1
Desert SW	523	2	-	-	-	-	-	-	523	2
RMPA	84	-	-	-	-	-	-	-	84	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	35,730	587	-	-	-	1	-	-	35,730	588

Regional Highlights

ERCOT Highlights

The unrestricted coincident long-term demand forecast for the ERCOT Region ranges from 63,898 MW in 2011 to 80,536 MW in 2021. The 2021 peak Total Internal Demand is 78,927 MW and the 2021 peak Net Internal Demand is 76,864 MW. The ERCOT Region has 72,905 MW of *Existing-Certain* generation and 8,607 MW *Existing-Other* generation, consisting of installed capacity of wind not counted towards Reserve Margins, for this assessment, representing a decrease of 32 MW since the *2010 Long-Term Reliability Assessment*. This decrease is the net result of the addition of new generation and mothballing or retirements of older gas-fired resources. Future capacity that is expected to be available during this long-term assessment period includes 3,558 MW of gas-fired generation, 1,845 MW of coal, 100 MW of biomass, 90 MW of solar photovoltaic generation, 1,240 MW from other generation. The nameplate capacity from wind turbines will amount to 1,504 MW, with an expected summer on-peak capacity of 131 MW and 189 MW of mothballed unit capacity expected to return to service for total of 7,153 MW of *Future-Planned* resources during the assessment period.

ERCOT has an adequate Adjusted Potential Reserve Margin through 2017. The 13.75 percent minimum Anticipated Resources Reserve Margin is maintained through 2013, but falls below the minimum target in 2014, based on currently-planned resources. However, no official suspensions of operation notices for generation have been received as a result of the Cross State Air Pollution Rule (CSAPR). ERCOT recently completed an assessment[147] of the proposed inclusion of Texas in the CSAPR. The assessment found that generators' current compliance plans will result in 1,200 to 1,400 MW of generation would be unavailable year-round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months.

Approximately 646 miles of new or rebuilt 345 kV transmission lines have been completed since the 2010 LTRA. A large number of transmission projects, including over 5,000 miles of new 345 kV lines, will be placed into service within the next five years, primarily due to additions ordered by the Public Utility Commission of Texas (PUCT) to complete its Competitive Renewable Energy Zones (CREZ) transmission plan.[148] An additional 1,140 miles of 138 kV transmission lines are projected to come into service during the assessment period. There are no known transmission constraints that appear to significantly impact reliability across the ERCOT Region.

There are no known major facility outages or regulatory restrictions that are currently known to impact reliable operations expected over the assessment period; however, the EPA mandated January 1, 2012 implementation date for the Cross State Air Pollution Rule (CSAPR) will result, based on documentation provided to the ERCOT Region Balancing Authority and Reliability Coordinator, in a reduction in available generating capacity and exacerbate the potential need for emergency actions in 2012 and beyond, including load shed, until retrofits and/or alternative resources are implemented. Additional impacts

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[147] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.
[148] http://www.texascrezprojects.com/default.aspx.

result from the other proposed EPA rules if sufficient time is not allowed for the implementation of various pending EPA regulations. A preliminary analysis of localized transmission system impacts due to pending EPA regulations (not including the CSAPR) indicates that the potential loss of 9,800 MWs of gas-fired generation would have impacts on transmission reliability in certain load center regions, likely requiring additional reactive devices and new import pathways into those regions. Redevelopment of existing generation sites in these areas with new generating units could reduce or delay the need for additional transmission infrastructure. If any issues arise, the outage coordination process addresses outages as well as potential constraints. If constraints are identified, remedial action plans or mitigation plans are developed to provide for preemptive or planned responses to maintain reliability. Interregional transfer capabilities are not generally relied upon to maintain transmission reliability and address capacity shortages, although emergency support arrangements are in place which provide for mutual support over the asynchronous ties or through block load transfers.

ERCOT maintains operating reserves through Regulation Service, Non-Spin Reserves and Responsive Reserve Service. In the event that peak demands are expected to exceed all available generation and operating reserves, ERCOT will implement its Energy Emergency Alert (EEA) plan, as described in Section 6.5.9.3.4 (2) of the ERCOT Protocols[149] and Section 4.5 of the ERCOT Operating Guides.[150] The EEA plan includes procedures for the use of interruptible load, voltage reductions, procuring emergency energy over the asynchronous ties, and managing ISO-instructed demand reductions.

There are no anticipated reliability concerns resulting from high-levels of demand response resources. ERCOT limits the participation of Load Resources (LRs) at 50 percent of the hourly Responsive Reserve Service (RRS) procurement, for which the minimum requirement is 2,300 MW. LRs are deployed automatically via under-frequency relays (UFR) in response to frequency excursions below 59.7 Hz, or through manual deployment during system emergencies (*i.e.,* EEA). There are no anticipated reliability concerns with distributed resource integration at this time.

[149] http://www.ercot.com/mktrules/nprotocols/current.

[150] http://www.ercot.com/mktrules/guides/noperating/cur.

FRCC Highlights

The 2011 long-term demand forecast for the FRCC Region is projected to increase from a Total Internal Demand of 46,091 MW in 2011 to 53,083 MW in 2021. The resources internal to the region that are relied on to meet the minimum Reserve Margin throughout the assessment period vary from 54,618 MW to 62,338 MW by 2021. The corresponding Reserve Margin varies from 18.4 percent to 24.2 percent throughout the planning horizon.[151]

There are 45 miles of 230 kV transmission lines under construction as of January 1, 2011. Currently, there are 374 miles of planned transmission lines identified throughout the 2011-2021 planning horizon. Increased west-to-east flow levels across the Central Florida metropolitan load areas may cause transmission constraints in the Central Florida area, requiring remedial actions (depending on system conditions). Permanent solutions have been developed and are being implemented. In the interim, remedial operating strategies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability.

There are potential impacts to reliability, pending the release of regulatory restrictions from EPA initiatives, with the following proposed rules:

- Resource Conservation Recovery Act (RCRA): coal combustion residuals and products
- Clean Water Act (CWA) waste water discharge regulation
- CWA section 316(b): cooling water intake structures
- Clean Air Act (CAA) – Maximum Achievable Control Technology (MACT): rulemakings for mercury and other hazardous air pollutants (HAPS)
- Cross State Air Pollution Rule (CSARP -CAIR replacement rule)
- Ambient Air Quality Standards (AAQS): fine particulate matter (PM2.5) sulfur dioxide (SO2), nitrogen dioxide (NO2) and ozone

In addition, regulation of greenhouse gases (GHG) under the Clean Air Act (CAA) as well as a series of other laws can also impact reliability.

[151] The FRCC method of calculating Reserve Margin treats Controllable Capacity Demand Response (CCDR) as a demand reduction and yields corresponding Reserve Margin values of 19.8 percent and 26.1 percent respectively.

MRO Highlights

The NERC *2011 Long-Term Reliability Assessment* will include newly defined Assessment Areas (previously called sub-regions) for the MRO Regional Entity. In previous assessments, the MRO Regional Entity had two sub-regions, defined as MRO-US and MRO-Canada. MRO previously collected data from individual utilities, companies, and Registered Entities within the MRO footprint and summed all data to reflect a total for the two sub-regions as well as the total for the MRO Region. However, the MRO-US and MRO-Canada sub-regions were not congruent or compatible with Planning Authority and/or ISO/RTO footprints, which created inherent challenges comparing Reserve Margins and other planning and operating information. In 2011, the MRO has collected narrative and data from four Planning Authorities that are now designated as the following Assessment Areas:[152]

- MISO
- MRO-MAPP
- MRO-Manitoba Hydro
- MRO-SaskPower (Saskatchewan Power Corporation)

Because the sum of the four Planning Authority footprints are not congruent with the MRO footprint, the MRO total for demand and generation is not reported in this year's report as it has been in past assessments. Therefore, this assessment will establish new benchmarks for comparing this year's newly-defined Assessment Areas with future year assessments.

MISO's membership has also experienced the following changes since the release of the NERC *2010 Long-Term Reliability Assessment*:

- Big Rivers Electric Corporation joined MISO on December 1, 2010.[153]
- First Energy and Cleveland Public Power exited MISO and consolidated into the PJM RTO on June 1, 2011.[154]
- Duke Energy Ohio and Duke Energy Kentucky plan to exit MISO and consolidate into the PJM RTO on January 1, 2012.[155]

The demand projections over the assessment period have been impacted by changes in the MISO membership and these changes will be reflected in this assessment. New member integration of Big Rivers Electric Corporation was also included in the 2010 forecast; however, the departure of First Energy, Cleveland Public Power, Duke Energy Ohio, and Duke Energy Kentucky will create notable changes in demand forecasts throughout the assessment period. MISO's Total Internal Demand and Net Internal Demand for the 2021 peak are forecasted to be approximately 100,927 MW and 93,109 MW respectively, which are down from the 2010 LTRA 2019 peak forecast of 119,110 MW and 115,769 MW

[152] The information collected from these four Planning Authorities is kept whole and reported as a NERC Reporting Area in this report to maintain the integrity and accuracy of the data. Since the MISO footprint is geographically contained and registered within three Regional Entities (MRO, RFC, and SERC), each of these three Regional Entities reviews the MISO section of this report.

[153] http://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/BigRiversElectricCorporationIntegratesintoMidwes tMarkets.aspx.

[154] http://www.firstenergycorp.com/content/dam/newsroom/files/news-releases/2009-07-31%20RTO.pdf.

[155] http://www.duke-energy.com/news/releases/2010052001.asp.

respectively. The forecasted MISO 2011-2021 annual growth rate is approximately 1.0 percent, which has slightly increased when compared to data from the same reporting entities a year earlier. The MISO forecast for *Existing-Certain* capacity is 107,051 MW for the 2011 summer season, a 12 percent decrease compared to last year. The majority of this resource reduction is due to First Energy's departure from MISO. *Future-Planned* and *Conceptual* resources anticipated to be in service by 2021 are expected to total approximately 6,953 MW of nameplate capacity. Of those resources, *Future-Planned* and *Conceptual* wind nameplate capacity are expected to account for approximately 4,342 MW. *Future-Planned* unit contraction accounts for approximately 5,719 MW of units departing the footprint by 2012, primarily due to the exit of Duke Energy. For the 2011-2021 assessment, the Anticipated Resources Reserve Margin falls from 23.1 percent to 15.1 percent.

The forecasted Mid-Continent Area Power Pool (MAPP) 2011-2021 annual growth rate is 2.3 percent, compared with last year's annual growth rate of 1.4 percent. Part of the higher annual growth rate can be attributed to the increasing development in the oil and gas production in the Bakken Formation in western North Dakota and Eastern Montana. In addition, the economy in the MAPP Assessment Area projects economic recovery to pre-recession conditions. Total and Net Internal Demand projections will increase to 6,035 MW and 5,905 MW, respectively by 2021. The key factor in increased load growth is based on the assumption that the economy has recovered enough to assume normal economic conditions. *Existing-Certain*, Other, and Inoperable capacity resources for the 2011 summer are projected to be 8,242 MW, of which 6,359 MW are *Existing-Certain* resources. An additional 343 MW of *Future-Planned* capacity is projected to be in-service by 2021. The Anticipated Resources Reserve Margins for MAPP ranges between 43.5 and 19.6 percent between 2011 and 2021, above both the MAPP target Reserve Margins of 15 percent for predominately thermal systems, and 10 percent for predominately hydro systems.

Within Manitoba Hydro, which is a winter-peaking Assessment Area, the Total Internal Demand for the winter is expected to increase from the forecasted peak of 4,517 MW in 2011 to 4,992 MW in 2021. The Total Internal Demand for the summer is expected to be much lower than the winter, with forecasted summer peak demand ranging from 3,167 MW in 2011 to 3,472 MW in 2021. Compared to last year's assessment, Total Internal Demand projections for the winter increased on average by approximately 2 percent. Approximately 148 MW of additional *Existing-Certain* capacity resources was added since the prior assessment. Manitoba Hydro projects 867 MW of capacity additions categorized as either *Future-Planned* of *Future-Other*, through 202. Manitoba Hydro is also projected the addition of 204 MW in 2012 from the Wuskwatim Generating Station and 630 MW in 2020 from the Keeyask Generating Station. In 2019, Manitoba Hydro expects to retire approximately 95 MW of coal generation at Brandon. During the assessment period, the Adjusted Potential Resources Reserve Margins are projected to range between 42 percent and 58 percent in summer, and 20 percent and 28 percent in winter. Manitoba Hydro has criteria for Anticipated Capacity Resource Reserve Margin that requires a minimum of 12 percent reserves above the forecasted peak demand. The Planning Reserve Margins are all well above Manitoba Hydro's minimum criteria.

Saskatchewan's 2011-2021 assessment forecasts an average annual increase in Total Internal Demand of 2.4 percent. The winter Total Internal Demand and Net Internal Demand are projected to increase to

4,294 MW and 4,203MW respectively by 2021. There are no significant changes to Saskatchewan's load growth. An average of 3,926 MW of capacity resources is expected to be in-service through the 2011 summer, 3,550 MW of which are categorized as *Existing-Certain*. Saskatchewan's Adjusted Potential Resources Reserve Margins during this assessment period are projected to range between 18 percent and 20 percent for the summer, and 14 percent and 16 percent for the winter. The Reserve Margin remains above Saskatchewan's target Planning Reserve Margin of approximately 13 percent.

MRO projects a number of transmission reinforcements and various transformer and substation expansions and upgrades to be completed during the assessment period. MISO forecasts 3,209 miles of new transmission lines as well as 3,220 miles of upgrades to be implemented by its Planning Authority footprint by 2021. More than half of the facility improvements are for reliability or the integration of renewable resources. Within the MAPP Planning Authority footprint, 480 circuit-miles of 345 kV circuit and 162 circuit-miles of 230 kV of planned facilities are projected to be installed in its Planning Authority footprint by 2021. These planned facilities are primarily for reliability improvements.

Manitoba Hydro plans to install 833 miles of 500 kV DC circuit, 31 miles of 500 kV AC circuit, and 455 miles of 230 kV circuits within its Province. These additions are primarily for the integrations of hydro resources. Approximately 149 miles of 230 kV circuits of planned facilities will be installed in Saskatchewan within the assessment timeframe. These planned facilities are primarily to meet the projected load growth.

Wind generation continues to be installed in the upper Midwest at a rapid pace, similar to the previous several years. As of June 2011, about 10,358 MW of *Existing-Certain* nameplate wind generation was reported by the four Planning Authorities. Approximately 3,700 MW of this capacity is installed in Iowa alone, second only to Texas in terms of state nameplate capacity increases in the US. However, wind generation installations in Iowa were negligible during the past 1.5 years due to transmission constraints. According to the Iowa Office of Energy Independence, lack of transmission line capacity is beginning to restrict further growth of wind farms in the state. While each Planning Authority assumes different availability at peak demand, the aggregation of all four Assessment Areas (MISO, MAPP, Manitoba, and SaskPower) results in approximately 826 MW, or roughly 8.0 percent of nameplate, will be available during peak demand.

The total projections for *Future-Planned* nameplate wind generation to be installed for the footprints of all four Planning Authorities by 2021 amounts to 2,043 MW. Of this amount approximately 12.7 percent or 259 MW are expected to be available during on-peak times. It is difficult to predict the wind capacity available on-peak due to the intermittent nature of wind. However, MISO determines maximum wind capacity credits using an Equivalent Load Carrying Capacity (ELCC), a metric commonly used by the National Renewable Energy Laboratory (NREL). Wind shows an *Existing-Certain* capacity of 389 MW on-peak based on an average 12.9 percent capacity credit and transmission constraints for those resources committed as a Planning Resource capacity to MISO within the Module E Capacity Tracking (MECT) tool.

NPCC Highlights

The five NPCC subregions (referred to as Assessment Areas within NPCC) are defined by the footprints of the following five Reliability Coordinators:

- Maritimes
- New Brunswick System Operator (NBSO)
- Nova Scotia Power Inc.
- Maritime Electric Company Ltd.
- Northern Maine Independent System Administrator, Inc.
- New England (ISO-NE): the ISO New England Inc.
- New York (NYISO): New York ISO
- Ontario (IESO): Independent Electricity System Operator
- Québec: Hydro-Québec TransÉnergie

The Maritimes and Québec Assessment Areas are winter-peaking systems (the internal summer peak for Québec can be as little as 60 percent of its internal winter demand); Ontario, New York and New England are summer-peaking systems.

The projected load growth over the long-term assessment period remains sluggish, due to a combination of energy Conservation initiatives and a slow economic recovery. Although four of the five Assessment Areas are reporting increased demand growth compared with 2010 projections (the largest such increase of 0.3 percent), New England growth remains unchanged at 1.4 percent when compared with the 2010 forecast.

The Regional System Plans (RSPs) for the ISO New England Inc. identify needed transmission improvements during the assessment period. The current plan builds on the results of previous RSPs and other regional activities. Transmission projects (detailed in the New England Assessment) have been developed to coordinate major power transfers across the system, improve service to demand and meet transfer requirements with neighboring Balancing Authorities.

In New York, Con Edison is also increasing the rating of two 345 kV cables between Farragut and East 13th Street by installing refrigerated oil cooling, as well as planned local transmission reinforcements of the sub-transmission system by Rochester Gas & Electric and Orange & Rockland Utilities.

In Ontario, plans are being considered for a 500 kV double-circuit transmission from Bruce to Milton. Furthermore, the additions of Static VAR Compensators are planned at both Detweiler and Nanticoke substations.

In Québec, a new 735 kV substation Aux Outardes will tap the existing Micoua to Manicouagan circuit. Two 735 kV lines will be redirected into the new station and one new 735 kV line will be built between Aux Outardes and Micoua.

In the Maritimes, the study of a 345 kV transmission line project is underway between Coleson Cove and Salisbury to better serve growing loads in southeastern New Brunswick. An interprovincial tie-line from

Salisbury, New Brunswick to Onslow, Nova Scotia, could allow for more renewable generation resources to be incorporated into the Maritimes generation mix, while also increasing tie capacity. The potential development of the Lower Churchill Generation Project in the Canadian provinces of Newfoundland and Labrador would result in the installation of an HVdc undersea cable link between that province and Nova Scotia. This would provide a transmission path for new sources of hydro energy to the Maritimes and New England Assessment Areas.

During the long-term assessment period, the challenges identified for the NPCC Regional Entity include aging infrastructure issues, the integration of variable resources and the retirement of fossil-fueled generation.

The NPCC Regional Entity oversees the reliability of the transmission system as well as the resource adequacy for all five Assessment Areas through NPCC Regional Reliability Reference Directory 1, "Design and Operation of the Bulk power system."[156]

The NPCC Regional Entity also implements a comprehensive resource assessment program, through Directory 1 to review resource adequacy. The primary objective of this resource review is to demonstrate that plans are in place within the Regional Entity for the timely acquisition of resources necessary to meet resource adequacy criterion.

The review of resource adequacy in each Assessment Area includes an evaluation and/or discussion of the following issues:

- Load model and critical assumptions on which the review is based
- Procedures used by the Area for verifying generator ratings and identifying de-ratings and forced outages
- Ability of the Area to reliably meet projected electricity demand, assuming the most likely load forecast for the Assessment 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

[156] http://www.npcc.org/documents/regStandards/Directories.aspx.

Section 5.2 of Directory 1 defines the criterion for resource adequacy for each Area as follows:

The probability (or risk) of disconnecting Firm load due to resource deficiencies shall be, on average, not more than one day in 10-years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. 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 Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

- Impact of any possible environmental restrictions

Each Assessment Area resource adequacy review is 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.

Complementing the resource assessments, the interconnection benefits assumed by each NPCC Assessment Area in demonstrating compliance with the NPCC resource reliability criterion are evaluated at least triennially for a window of five years.

In parallel with the NPCC resource review, periodic reviews of the reliability of the planned bulk power transmission systems of each Area are also conducted through Directory 1. Each Assessment Area is required to present an annual transmission review assessing its planned transmission network four to six years in the future.[157] Depending on the extent of the expected changes to the system studied, the review presented each year by the Assessment 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 reviews will be conducted 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.

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"

[157] In the years between Comprehensive Reviews, an Assessment Area will annually conduct either an Interim Review, or an Intermediate Review, depending on the extent of the system changes projected for the Area since its last Comprehensive Review. Both the Comprehensive Review and the Intermediate Review analyze the steady state performance of the system, the dynamic performance of the system, and the response of the system to extreme system conditions. Each review will also discuss special protection systems and / or dynamic control systems within the Area, the failure or misoperation of which could impact neighboring Areas or Regions.

- TPL-004-0, "System Performance Following Extreme BES Events"

Among its various coordinated operational initiatives, NPCC has adopted measures to respond to potential geomagnetic disturbance (GMD) events as identified in the NERC report.[158] Linking its five Reliability Coordinators, NPCC has implemented a solar notification and communication system, entitled the Geomagnetic Storm Mitigation System (GSMS), contracted through Solar Terrestrial Dispatch. An active communications software package installed on the system operator's console provides each of the NPCC Reliability Coordinators with geomagnetic storm alerts as well as the status of solar activity. Upon receipt of a geomagnetic storm alert of K_p=6 or higher, the GSMS will simultaneously provide system operators with the following capabilities:

- Visual and/or audible alarms along with an interface with current known information regarding solar activity
- A dialog box permitting instantaneous communication among all NPCC Reliability Coordinators of any observed solar magnetic activities

Complementing the notification system, NPCC also maintains its Document C-15, "Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems," establishing protective measures which can be taken to minimize the vulnerability of the system to solar phenomena. After reviewing the available data provided by the GSMS, the system operator may choose to enact one or more of the actions presented in Document C-15.

[158] *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System:* http://www.nerc.com/files/HILF.pdf.

RFC Highlights

All Reliability*First* Corporation (RFC) members are affiliated with either the MISO (Midwest ISO) or the PJM RTO for market operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission company located in Indiana, Kentucky and Ohio, is not a member of either RTO and is not affiliated with either markets. OVEC's Reliability Coordinator services are performed by MISO as of June 1, 2011, when this entity exited PJM. RFC does not have officially designated subregions. MISO and PJM each operate as a single Balancing Authority. Since all RFC demand is in either MISO or PJM (except for the small load (less than 100 MW) within the OVEC Balancing Authority area) the reliability of the PJM RTO and Midwest ISO are assessed and the results used to indicate the reliability of the RFC Region.

The forecast for the 2011 PJM RTO summer peak is 148,941 MW which includes the integration of FirstEnergy (ATSI) and Cleveland Public Power (CPP) into PJM. FirstEnergy (ATSI) and CPP load is expected to contribute 13,364 MW to the 2011 PJM peak. The forecast for the 2012 PJM RTO summer peak is 158,631 MW which includes the integration of Duke Ohio and Duke Kentucky (DEOK) into PJM. Duke's load is expected to contribute 4,500 MW to the 2012 PJM peak. Summer peak load growth for the PJM RTO (with ATSI, CPP and DEOK) is projected to average 1.3 percent per year over long-term assessment. Because of the significant differences with the addition of FirstEnergy (ATSI), CPP and DEOK comparisons with previous years are misleading. Significant differences in the forecast of Net Internal Demand from the 2010 Load Report result from including the load of FirstEnergy (ATSI) and CPP starting in June 2011 and DEOK starting January 2012, a weaker economic forecast, and an increase in expected Load Management and Energy Efficiency impacts. The PJM RTO (with ATSI, CPP and DEOK) summer peak is forecasted to be 176,060 MW in 2021, a total increase of 21,677 MW, compared to 2011.

The demand projections over the assessment period are significantly affected by changes in the MISO's membership. New member integration of Big Rivers Electric Corporation in September of 2010 and the departure of FirstEnergy in June 2011 result in changes in demand forecasts throughout the assessment period. Relative to previous projections the MISO load forecasts have declined during the assessment period. MISO's Total Internal Demand and the Net Internal Demand for the 2021 peak demand projection is 106,984 MW and 93,109 MW, respectively.

The estimated coincident Net Internal Demand peak of the entire Reliability*First* Region for the summer of 2011 is projected to be 163,100 MW. For the summer of 2021, Net Internal Demand is projected to be 187,900 MW. The TID for the summer of 2011 is projected to be 177,600 MW. For the 2021 summer, Total Internal Demand is projected to be 198,000 MW.

PJM has 180,395 MW of *Existing-Certain* capacity for the 2011-2012 planning period. With the addition of ATSI, CPP and DEOK and changes in the other PJM companies, the PJM generating resources have increased by 13,000 MW.

Total capacity is affected by the changes in MISO's membership. Primarily driven by the June 2011 departure of FirstEnergy and offset by new member integration, approximately 12,000 MW of *Existing-Certain* resources have been removed since the prior reporting year. The amount of *Existing-Certain* capacity in Reliability*First* is 211,700 MW. This is a 2.5 percent decrease from the prior reporting year of 217,100 MW.

Future-Planned resources increase the PJM capacity by 8,200 MW by the end of the assessment period. No *Existing-Other* or Inoperable resources are considered. There have been several significant capacity additions, including a large coal unit, many large natural gas-fired units, significant amounts of wind and solar development and a nuclear unit in Virginia.

Capacity additions throughout the MISO footprint consist primarily of renewable energy resources (wind and biomass) with a potential total of approximately 14,700 MW of additions. The nameplate rating increase in *Future-Planned* capacity additions through 2021 in Reliability*First* is 34,600 MW.

The PJM Reserve Margin requirement during the entire assessment period ranges between 15.3 and 15.6 percent. PJM is expected to meet its Reserve Margin requirements throughout the assessment period, except for the last planning period (2020) but it has over 34,000 MW of *Conceptual* generation in its interconnection queues of which approximately 20 percent is expected to come on-line.

The MISO Reserve Margins projected through the assessment timeframe vary with projected changes in the membership. The most recent Loss of Load Expectation (LOLE) study established a 17.4 percent Reserve Margin level, in order to maintain a 1 day in 10-year reliability level. Throughout the assessment period the Reserve Margin only falls below that target for 2021, when using the Anticipated Resource expansion. When considering the Adjusted Potential Resources expansion the reserve levels are their lowest in 2021 when they fall to 36.2 percent.

Analyses were conducted by the Midwest LOLE Working Group and PJM to satisfy RFC regional reliability standard BAL-502-RFC-02, which requires Planning Coordinators to determine the Reserve Margin at which the Loss of Load Expectation (LOLE) is one day in 10-years (0.1 day/year) on an annual basis for their planning area. These analyses include demand forecast uncertainty, outage schedules, determination of transmission transfer capability, internal deliverability, other external emergency sources, treatment of operating reserves and other relevant factors when determining the probability of Firm demand exceeding the available generating capacity. The assessment of PJM resource adequacy was based on reserve requirements determined from the PJM analysis. Similarly, the assessment of MISO resource adequacy was based on reserve requirements determined from the MISO analysis. Since PJM and MISO are projected to have sufficient resources to satisfy their respective Reserve Margin requirements, the RFC region is projected to have adequate resources for the assessment period.

Many new additions to the bulk power system since the last assessment have been placed in-service within the Reliability*First* footprint. These include a total of 500 miles of transmission line at 138 kV and above, plus sixteen new or replacement transformers with a total capacity of 10,080 MVA. An additional 2,470 miles of transmission line at 138 kV and above, plus forty-five new or replacement transformers with a total capacity of 26,840 MVA are expected to be placed in-service through the end of the assessment timeframe. These system changes are expected to enhance reliability of the bulk power system within Reliability*First*.

SERC Highlights

SERC-E

SERC-E is a summer-peaking area covering portions of North Carolina and South Carolina. The five Balancing Authorities in this area are

- Alcoa Power Generating, Inc. – Yadkin Division
- Duke Energy Carolinas
- Progress Energy Carolinas
- South Carolina Electric & Gas Company
- South Carolina Public Service Authority

The forecasted summer Total Internal Demand for utilities in SERC-E increases from 43,249 MW in 2011 to 49,640 MW in 2021. The projected 2021 Net Internal Demand is 47,400 MW. Comparisons to the previous year's forecast are not available due to the restructuring and resulting introduction of a new Assessment Areas. However, entities report that the demand forecasts reflect an economy that is expected to grow at a slower rate based on modest increases in wholesale and retail sales and customer growth. Companies within SERC-E expect to have 50,063 MW of *Existing-Certain* and 115 MW of *Existing-Inoperable* on-peak capacity in 2011. No additional *Existing-Certain* capacity has been added to the system since 2010. An additional 3,691 MW of *Future-Planned* resources are projected to be in service through the end of the assessment period. Currently, there are approximately 800 MW of old-fleet combustion turbine units and 1,000 MW of non-scrubbed coal units that are scheduled for retirement during this assessment period. The reliability impacts of these retirements are being coordinated with the North Carolina Utility Commission. As material adverse impacts on system reliability are identified, utilities will prepare modifications to the retirement plan. Projected Anticipated Capacity Resource Reserve Margins for utilities in SERC-E range from 23.9 percent in 2011 to 14.6 percent in 2021. Both the 2021 Prospective and Adjusted Potential Resources Reserve Margins for the SERC-E Assessment Area are both projected to be 14.6 percent. There are no Regional or Assessment Area targets or Reserve Margin criteria within SERC-E. *Existing-Certain* Reserve Margins fall below the NERC Reference Margin Level of 15.0 percent in 2021; however, entities continue to project margins based on load reductions due to the economy, increased Demand-Side Management (DSM), significant increases in generation, and the effects of adverse weather on generating units. To obtain the needed capacity, company procedures allow entities to adjust their resource portfolios in order to use resources from purchases, DSM, new generation, reserve-sharing agreements, or a combination of these resources. Additionally, significant assessment findings have been disclosed, indicating near-term economic growth becomes more sluggish for the entire long-term assessment period. Projections have been adjusted to reflect these changes. No other issues are reported as a concern for the area.

Utilities have placed 4 miles of 100-120 kV and 153 miles of 200-299 kV transmission lines in-service since the 2010 summer. In addition, 403 miles of 100-120 kV, 17 miles of 151-199 kV, and 932 miles of 200-299 kV transmission lines are planned to be in-service by 2021. No transmission reliability concerns are expected to significantly impact Bulk Electric System reliability during this assessment period. Coordinated regional, subregional, and specific company studies are performed on a routine basis.

Currently, there are no significant challenges that impact system reliability. Entities in the SERC-E Assessment Area will continue to monitor reservoir levels as seasonal conditions change. Loop and parallel flows imposed by neighboring Balancing Authorities have the potential to create contingency overloads; however, procedures and agreements are in place to effectively manage these flows on the system.

SERC-N

SERC-N is a summer-peaking area covering portions of 11 states.[159] This Assessment Area consists of six Balancing Authorities:

- Associated Electric Cooperative, Inc.
- Batesville Balancing Authority
- East Kentucky Power Cooperative
- Electric Energy, Inc.
- LG&E and KU Services Companies (as agent for Louisville Gas and Electric Company and Kentucky Utilities Company)
- Tennessee Valley Authority (TVA)

The forecasted summer Total Internal Demand for utilities in SERC-N increases from 46,846 MW in 2011 to 52,189 MW in 2021. The projected 2021 Net Internal Demand is 48,495 MW. Comparisons to the previous year's forecast are not available due to the restructuring and resulting introduction of a new Assessment Areas. However, entities identified no significant differences between last year's demand forecast versus this year's projections. Companies within SERC-N expect to have 57,034 MW of *Existing-Certain*, 501 MW of *Existing-Other*, and 639 MW of *Existing-Inoperable* capacity on-peak in 2011. Since 2010, the amount of *Existing-Certain* capacity has increased by 785 MW. There are 1,036 MW of *Future-Planned* resources projected to be in-service by 2021. At least 2,100 MW will be retired on the TVA system in the next 6 years. TVA is currently preparing for the retirements with alternative generation. Projected Resource Reserve Margins for the utilities within SERC-N range from 29.4 percent in 2011 to 18.4 percent in 2021. The summer peak for 2021 *Existing-Certain* and Net Firm Transactions and Adjusted Potential Reserve Margins for the utilities in the SERC-N Assessment Area are both projected to be 20.0 percent. Entities within this SERC-N do not adhere to any Regional or Assessment Area targets or Reserve Margin criteria; however, these margins are above the 15.0 percent NERC Reference Margin Level. Entity processes continue to consider modest growth in customer demand, derates (unusually high river temperatures limiting once-through cooling systems) and other outages into short-term projections to ensure reliability. No other concerns are anticipated for this assessment period.

Since the 2010 assessment, utilities have added 7 miles of 100-120 kV and 51 miles of 151-199 kV new transmission lines. By 2021, entities are planning for an additional 39 miles of 100-120 kV, 87 miles of 121-150 kV, 565 miles of 151-199 kV, 164 miles of 300-399 kV, and 137 miles of 400-599 kV transmission lines to be in service. No transmission reliability concerns are expected to significantly impact Bulk Electric System reliability for this assessment period. System conditions may at times dictate local area

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[159] Alabama, Georgia, Illinois, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee and Virginia.

generation re-dispatch or reconfiguration of transmission elements to alleviate anticipated contingency overloads. NERC Transmission Loading Relief (TLR) procedures are commonly invoked in scenarios that are not easily remedied by a local area solution. Entities regularly evaluate the transmission system to identify any future constraints and mitigate concerns that could significantly impact reliability.

Utilities within SERC-N continue with restoration efforts following the severe tornadoes experienced during April 2011. Weather-related disaster management is achieved by maintaining formalized procedures, processes, and personnel training to ensure impacts are minimized.

SERC-SE

SERC-SE is a summer-peaking Assessment Area covering portions of Alabama, Georgia, Mississippi, and Florida. This reporting area consists of four Balancing Authorities:

- PowerSouth Energy Cooperative
- South Mississippi Electric Power Association
- Southeastern Power Administration
- Southern Company Services, Inc.

The forecasted summer Total Internal Demand for the utilities in SERC-SE increases from 49,314 MW in 2011 to 58,359 MW in 2021. The projected 2021 Net Internal Demand is 56,042 MW. Due to the restructuring and introduction of Assessment Areas, comparison of prior year forecasts is not available; however, entities expect to see slowed growth due to the results of the sluggish economic growth. Companies within SERC-SE anticipate there will be 61,072 MW of *Existing-Certain*, and 3,301 MW of *Existing-Other* capacity available on-peak in 2011. Since the 2010 assessment, the amount of *Existing-Certain* capacity in 2011 has increased by 822 MW. Entities anticipate 5,827 MW of *Future-Planned* resources to be in service by 2021. In addition, there are no known retirements that may impact reliability during this assessment period. Potential environmental regulations could lead to unit retirements during the long-term planning horizon and utilities are currently evaluating the potential reliability impacts. Anticipated Reserve Margins for utilities in SERC-SE range from 24.3 percent in 2011 to 17.8 percent in 2021. The summer 2021 Prospective and Adjusted Potential Reserve Margins for SERC-SE utilities are both projected to be 23.1 percent. Most entities within SERC-SE use a reference Reserve Margin level of 15.0 percent to ensure reliability, and project Reserve Margins will remain above this target through the assessment period. Entity processes continue to capture and consider weather, economic, and demographic conditions in their projections through models and assessments that take into account historical peaks and various conditions that affect the system. As conditions from the economic downturn continue to indicate slow growth, entities account for this trend in their models through the reduction of load.

Utilities within SERC-SE have placed 12 miles of 100-120 kV, 8 miles of 151-199 kV, and 11 miles of 200-299 kV transmission lines in service since the 2010 summer. Utilities within the Assessment Area are planning an additional 1,100 miles of 100-120 kV, 38 miles of 151-199 kV, 882 miles of 200-299 kV and 81 miles of 400-599 kV transmission lines to be in-service by 2021. No transmission reliability concerns are expected to significantly impact Bulk Electric System reliability for this assessment period. To minimize impacts on the system, utilities SERC-SE annually develop near- and long-term assessments of the transmission system. The results of these studies are used to develop mitigation projects are added to company transmission expansion plans. The inclusion of these projects, along with preventative maintenance, will help ensure that any reliability concerns are met during throughout the long-term planning period.

In addition to addressing system issues within transmission system assessments, entities are preparing themselves to address possible reliability impacts of potential EPA regulations and other climate legislation. These impacts may lead to the unavailability of significant amounts of existing generation. Furthermore, the inability to procure and construct replacement generation within a given timeframe could present a reliability concern. Entities will continue to evaluate the situation and work toward solutions any potential unit retirements.

SERC-W

SERC-W is a summer-peaking Assessment Area covering portions of Arkansas, Louisiana, Mississippi, and Texas.[160] The 10 registered Balancing Authorities in this Area are:

- Entergy
- City of Benton, AR
- City of Conway, AR
- City of North Little Rock, AR
- City of Osceola, AR
- City of Ruston, LA
- City of West Memphis, AR
- Louisiana Generating, LLC
- Plum Point Energy Associates, LLC
- Union Power Partners; L.P.

The forecast summer Total Internal Demand for utilities in SERC-W increases from 25,101 MW in 2011 to 28,809 MW in 2021. The projected 2021 Net Internal Demand is 27,840 MW. Although a comparison of the forecast to prior years is not available due to the restructuring and introduction of Assessment Areas, entities within SERC-W reported forecasts that indicate continued poor economic conditions throughout 2011 with a gradual return to normal conditions by 2015. No changes were made to assumptions for normal-weather conditions from last year's forecast. Companies within SERC-W expect to have 35,140 MW of *Existing-Certain*, 3,544 MW of *Existing-Other*, as well as 1,255 MW of *Existing-Inoperable* capacity on-peak in 2011. Since the 2010 assessment period, the amount of *Existing-Certain* capacity has not increased. Entities anticipate the addition of 234 MW of *Future-Planned* resources by 2021. Although several expected retirements have recently been announced, entities do not anticipate any unit retirements that could affect reliability during the assessment period.

Anticipated Capacity Resource Reserve Margins range from 40.2 percent in 2011 to 5.4 percent in 2021. Both the 2011 Prospective and Adjusted Potential Resource Reserve Margins for the utilities in SERC-W

[160] SERC-W also includes Southwest Power Pool RC entities registered in SERC.

are both projected to be 41.0 percent. The entities within this Assessment Area do not adhere to any regional or Assessment Area targets or Reserve Margin criteria. Reserve Margins are well above the 15.0 percent NERC Reference Margin Level for the majority of the assessment period, falling below 15.0 percent in 2018. However, entities are considering contracted resources, as well as self-build projects to address future reliability and resource needs. Current entity processes in assessing demand, capacity, and Reserve Margin projections are consistent with prior years, even with the changing boundaries. Assuming the addition of contracted resources or self-build projects, no resource reliability concerns are expected through 2021.

Utilities within SERC-W have placed 5 miles of 151-199 kV and 11 miles of 200-299 kV transmission lines in-service since the 2010 summer. An additional 364 miles of 100-120 kV, 184 miles of 121-150 kV, 43 miles of 151-199 kV, and 310 miles of 200-299 kV transmission lines are planned by 2021. No transmission reliability issues are expected to significantly impact Bulk Electric System reliability for this assessment period. In addition, companies within SERC-W regularly participate in the SERC Near-Term Study Group (NTSG) seasonal reliability studies and develop assessment plans to ensure system reliability.

Entities within SERC-W are studying system reliability with a critical and conservative approach. Any issues that result from these studies will be addressed within the appropriate timeframe. Curtailment Processes and Emergency Response Plans are routinely updated. Transmission-wide and local area procedures, re-dispatching, and operating guidelines will be implemented as necessary to maintain reliability. Because Energy Emergency Alerts (EEAs) have been issued in the past for the Acadiana area, the Southwest Power Pool Independent Coordinator of Transmission-Entergy (SPP-ICTE) will continue to closely monitor this area. If necessary SPP-ICTE will implement mitigation plans as part of its role as a Reliability Coordinator. A two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket is currently under construction and expected to be in-service during 2012. There are no other anticipated reliability concerns for the SERC-W Assessment Area.

SPP Highlights

The *2011 Long-Term Reliability Assessment* data was collected for the SPP Regional Transmission Organization (RTO) footprint which now includes three Nebraska members as well as the Arkansas Electric Cooperative Corporation's (AECC) Entergy footprint.[161] The long-term demand forecast for the 2011-2021 assessment period is projected to be approximately 18.5 percent higher compared to the 2010 LTRA, due to the inclusion of the Nebraska entities and AECC.[162] The SPP RTO's Total Internal Demand is projected to be 58,948 MW in 2021, with a total capacity amounting to 82,038 MW. Approximately 14,908 MW of *Existing-Certain* resources have been added since last year. The SPP RTO expects the addition of 5,437 MW of *Future-Planned* resources between 2011 and 2021. Although no significant variable capacity additions or unit retirements are projected, SPP is internally evaluating the impacts of proposed Federal environmental regulations on both coal and gas-fired generation. The SPP RTO currently has 28,164 MW of generation (mostly wind) in the Generation Interconnection queue.

The SPP RTO's minimum capacity margin requirement is 12 percent, which translates to a Reserve Margin of 13.6 percent.[163] The 2011-2021 assessment period Reserve Margin for the SPP RTO Assessment Area, based on *Existing-Certain* and Net Firm Transactions, amounts to 26.9 percent in 2011, and decreases to 14.3 percent in 2021. The Anticipated Resources Reserve Margin is 27.2 percent in 2011 and decreases to 23.6 percent in 2021. The Adjusted Potential Resources Reserve Margin is 35.5 percent in 2011 and decreases to 32.8 percent in 2021. No concerns regarding resource reliability have been identified for the 2011-2021 assessment period, as all Reserve Margins remain above the SPP target.

Approximately 255 miles of new transmission facilities and three bulk system transformers were added to the SPP RTO since 2010. For this assessment period, approximately 3,000 miles of the additional transmission lines are projected to be in-service by 2021.

The amount of in-service wind generation in the SPP Region continues to increase, and the operational impacts to regulate and control the performance of this variable generation are still unknown. As additional wind generation is built in the western area of the SPP RTO, the organization will continue to implement operating procedures to address any potential reliability issues. Due to its variable nature, increased wind generation could have a significant impact on operations. A number of avenues are being explored to provide transmission outlets for new wind generation during the next decade. SPP's Wind Integration Task Force (WITF) and various other groups continue to work together on transmission expansion planning activities that will ultimately facilitate access to wind and generation.[164]

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[161] Arkansas Electric Cooperative Corporation's Entergy footprint is included with SPP's assessment due to NERC's restructuring of reporting responsibilities.

[162] The Nebraska utilities include Omaha Public Power District, Nebraska Public Power District and Lincoln Electric System. These utilities have a combined projected 2011 peak demand of 6,101 MW. AECC's footprint has a projected 2011 peak demand of 1,740 MW.

[163] The SPP Criteria are in the Governing Documents folder of the SPP.org *Documents and Filings* library. A link is at the top of the Org Groups page: http://www.spp.org/publications/Criteria04-27-2010-with%20AppendicesCurrent.pdf.

[164] Access the SPP WITF Wind Integration Study from the Org Groups page of SPP.org, Wind Integration Task Force section: http://www.spp.org/section.asp?group=1385&pageID=27.

To ensure the most efficient and effective use of renewable resources, SPP's operations staff must maintain and enhance the ability to project how much wind generation will be available to reliably serve load over given time periods. Unpredictability remains the largest obstacle in effectively integrating wind energy into SPP's generating mix. As wind speeds change, utilities must instantaneously switch to and from other generating resources to compensate for this variability. Increased accuracy in capabilities to forecast the time, location, and speed of wind will significantly enhance the ability of operators to reliably manage the grid. In 2011, SPP implemented a new wind forecasting tool to generate five-minute, hourly, and day-ahead projections.

WECC Highlights

Summer Total Internal Demand for the Western Electricity Coordinating Council (WECC) is projected to increase annually by 1.54 percent, from 149,714 MW in 2011 to 177,123 MW in 2021. Last year's projected increase was 1.4 percent for the 2010 to 2019 period. Summer Net Internal Demand is also projected to also increase by 1.54 percent percent, from 145,285 MW in 2011 to 171,893 MW in 2021. *Existing-Certain* net resources have increased to 201,294 MW compared to the 184,468 MW reported in last year's assessment. About 10,000 MW of the increase is due to decreased scheduled on-peak maintenance. *Future-Planned* net resource additions from 2011 through 2021 are projected to be 54,416 MW while adjusted *Conceptual* net resource additions are projected to be 10,147 MW. The associated Anticipated Capacity Resources (ACR) and Adjusted Potential Resources (APR) margins are 47.3 percent and 53.1 percent, respectively, for 2021.

Significant transmission additions since last year include completion of a significant portion of the Gateway West project. The Gateway West project is planned to move renewable resources power from Wyoming to loads centers west and southwest of Wyoming. Several additional transmission projects for delivering renewable and other generator output to load centers are discussed in the subregion sections of this assessment.

Important challenges to operation of the bulk power system during the assessment period relate to the significant shift to renewable resources. This shift involves transmission additions to move the power from remote generation sites to load centers and introduces additional complexities such as excess off-peak energy generation and control performance issues created by constantly, and sometimes rapidly, changing wind-powered generation. Plans and procedures to address these issues are discussed in further detail later in WECC's Regional Assessments.

ERCOT

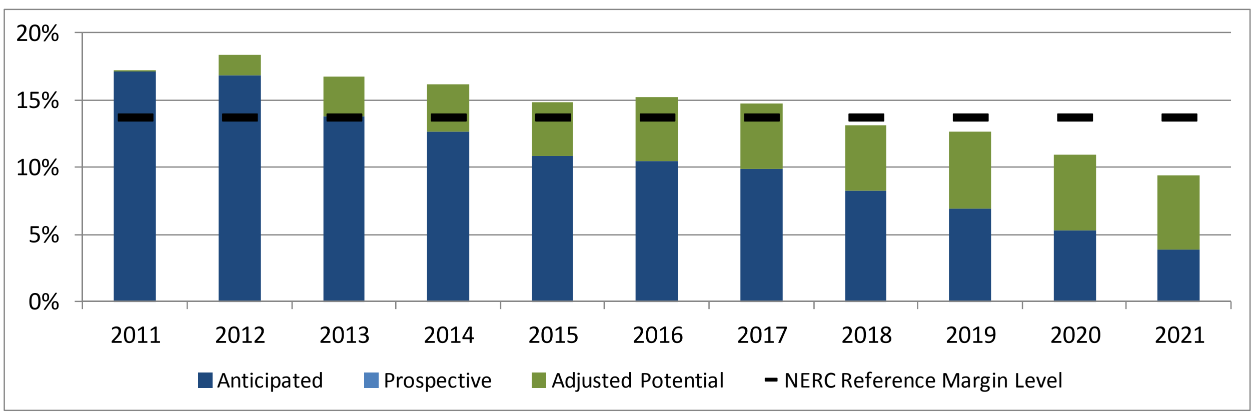
Introduction

The ERCOT Region is a separate electric interconnection located entirely in Texas. ERCOT acts as the sole Balancing Authority (BA) for the ERCOT Region, and also performs market functions, reliability coordination, and long-term planning. The generation capacity data included in this assessment is reported to ERCOT by the generation owners. The demand forecast is developed by ERCOT based on economic indicators, weather, and historical regional loads. This report provides an assessment of the reliability, resources, demand, and transmission infrastructure in the ERCOT Region.

Reliability Assessment

ERCOT projects an adequate Reserve Margin through 2013, based on Anticipated Capacity resources.[165] The Reserve Margin falls below the ERCOT designated 13.75 percent Reference Reserve Margin level used throughout the assessment period, starting in 2014 and remains below this level through the remainder of this long-term assessment period (Figure 73). While there is continued load growth and uncertainty in resource additions, significant *Conceptual* resources are under study. The minimum Reference Reserve Margin level of 13.75 percent is based on a Loss-of-Load Expectation (LOLE) analysis,[166] resulting in no more than one day in 10 years loss of load.

Figure 73: Annual On-Peak Planning Reserve Margins



ERCOT relies almost entirely on internal resources to serve its load and reserves. ERCOT currently has 85,424 MW of installed capacity, including Supply-Side Demand Response and mothballed units, with additional signed interconnection agreements for 8,337 MW of new nameplate generation capacity through 2021.

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[165] See the "Terms Used in This Report" section for additional information on capacity definitions.

[166] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip.

5,126 MW of behind-the-meter generation is projected to be available to the grid at time of summer and winter peaks, and is considered in this reliability assessment as load reductions.[167] Distributed resources are not explicitly counted towards reserves.

With multiple sources of fuel supply, traditional fossil fuel interruptions are not expected to be an issue in ERCOT. In order to be prepared for an extended forced outage, generation deliverability studies are conducted by security constrained unit commitment and dispatch software that ensure enough generation is capable to meet non-coincident peak load post-contingency.

Only 8.7 percent of existing wind generation nameplate capacity is counted as *Existing-Certain* generation, based on a 2007 study of the effective load carrying capability of wind generation in the region.[168] The remaining existing wind capacity amount is included in the *Existing-Other* generation amount. As solar continues to grow as a maturing resource in the ERCOT market, the effective load carrying capability of this resource will be studied. Beyond adding new transmission for CREZ, ERCOT and transmission service providers are also developing coordinated plans for reactive power control strategies in certain areas. ERCOT has developed numerous forecasting and operational tools which allow reliable integration of wind resources.

The Renewable Portfolio Standard (RPS)[169] for Texas (including areas of Texas that are outside the ERCOT Region) is 5,880 MW of installed renewable capacity by 2015 and 10,880 MW of installed capacity by 2025. Each entity that serves load is required to obtain new renewable energy capacity based on their market share of energy sales, multiplied by the renewable capacity goal. The 2025 target has already been met by Load Resources (LRs),[170] are eligible to provide up to 50 percent of ERCOT's hourly procurement of Responsive Reserve Service (RRS), and are considered an offset to the peak demand forecast in the ERCOT Reserve Margin calculation. Based on the methodology included in Planning Guide 8,[171] LRs' contribution to the Reserve Margin is calculated as a probability analysis, with a 95 percent confidence factor, representing the likely capacity available during summer peak hours.

ERCOT has not received notification that any additional currently operational units are planned to be retired or mothballed during this assessment period. ERCOT initiates studies when a resource submits a Notice of Suspension of Operations in order to determine if the resource is needed for Reliability Must Run service. Due to recent capacity insufficiencies, ERCOT recalled two mothballed units for an additional 414 MW.

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[167] Reported to ERCOT annually by the respective owners.

[168] The 8.7 percent of wind installed capacity is based on a 2007 study of the effective load-carrying capability (ELCC) of wind generation. The 2010 LOLEv Study updated the ELCC calculation, but ERCOT did not adopt the revised ELCC for use in Reserve Margin calculations. LOLEv Study: http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

[169] http://www.puc.state.tx.us/rules/statutes/Pura09.pdf; Section 39.904.

[170] Formerly known as Loads acting as a Resource (LaaRs).

[171] http://www.ercot.com/content/mktrules/guides/planning/current/08-050111.doc.

ERCOT plans grid enhancements as needed in a continuous process and does not plan for additional Under Voltage Load Shed (UVLS) schemes as a reliability tool. UVLS assessments are conducted periodically when changes in system configuration or operation warrant review, or are mandated by NERC Standards. ERCOT coordinates the assessments with the local Registered Entities that use UVLS schemes. The ERCOT Region currently has UVLS schemes established in the following areas:

- Houston (~5,333 MW)
- Dallas/ Fort Worth (~2,971 MW)
- Laredo (~200 MW)
- Rio Grande Valley (~473 MW)

UVLS deployments are intended to provide a "safety net" in case other operations are unable to resolve under voltage problems. UVLS schemes are not generally relied upon to recover from NERC Category B and C events, and system reinforcements may be made to limit the amount of load shed that would be necessary in localized urban areas under certain NERC Category D events. One additional Special Protection System (SPS) has been proposed to monitor the lines adjacent to the Barney Davis generation site at the request of the Resource. The retirement of four SPSs are planned in the LTRA timeframe due to transmission enhancements.

There is no formally established planning process for catastrophic events. To the extent that ERCOT is made aware of an impending event, the Region will take preventative measures as necessary, including orders for the withdrawal of planned outages, orders for additional generation, inquiring about extra assistance across the asynchronous ties, and finally, performing special engineering studies to evaluate potential worst-case scenarios.

The Planning Authority and Transmission Planners (TP) in the Region participate in the established, interconnection-wide planning process, including the development of the annual ERCOT Five-Year Transmission Plan and the ERCOT long-term planning process. In addition, each TP performs additional analysis of their portion of the ERCOT system. The ERCOT Five-Year Transmission Plan is performed to identify transmission system needs for years one through five and is used to satisfy, in part, NERC TPL-001-1, TPL-002-1, TPL-003-1, and TPL-004-1 requirements. The 2010 Five-Year Transmission Plan analysis identified 52 reliability projects to be implemented between 2011 and 2015.

In the planning horizon, the ERCOT Five-Year Transmission Plan study and additional voltage stability studies of future-year network conditions identify limiting elements under contingency. ERCOT staff then proposes projects to mitigate the problems as needed. In the operating horizon, reactive margins are maintained in the major metropolitan areas. Areas of dynamic and static reactive power limitations include:

- Corpus Christi
- Houston
- Dallas/Fort Worth
- Rio Grande Valley
- South to Houston generation
- South to Houston load

- North to Houston generation
- North to Houston load.

The Operating Procedure Manual for the Transmission and Security Desk,[172] specifically Procedure 2.4.3, (Voltage Security Assessment Tool), describes the procedure to monitor the system and to prevent voltage collapse using an online voltage stability analysis tool.

ERCOT plans for a 5 percent voltage stability margin for NERC category B contingencies and a 2.5 percent margin for NERC category C contingencies.[173] 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. Potential problems are reported to ERCOT System Planning and the affected transmission owners to develop corresponding transmission projects to resolve the lack of voltage stability margin and to Transmission Operators (TOPs) for their re-assessment for the operating horizon. Impacts of newly developed NERC Standards are reviewed and re-assessments are conducted by ERCOT and Registered Entities as needed.

Active power and reactive power flow-control devices, such as phase-shifting transformers, switchable series reactors and flexible AC transmission systems (FACTS) devices have been added to the ERCOT system to mitigate transmission constraints and improve system efficiency. In addition, ERCOT staff and ERCOT stakeholders are evaluating various new technologies that are expected to be deployed within the ERCOT system over the coming years with potential impacts on grid operations and reliability. These include synchrophasors to monitor the stress of the system; utility-scale batteries and other storage devices that are potentially capable of providing ancillary services; distributed generation deployed to provide backup power for severe weather events but also potentially available to help address electric grid capacity shortfalls; and plug-in electric vehicles with accompanying “smart charging” price offerings to encourage off-peak charging. A major deployment of smart meters is underway by utilities in ERCOT that serve the competitive retail areas of the ERCOT system. By 2014, a total of more than 6 million advanced meters are expected to be deployed and operational. Customers at those meter sites will have their retail accounts settled at the ERCOT wholesale market level based on their 15-minute interval electricity use. Smart meters in turn may lead to deployment of home area networks providing tools for these consumers to manage their electricity demand more efficiently. This combination of tools is expected to bring additional retail-level Demand Response to the ERCOT Region. While such Demand Response will not be dispatchable, it is projected to have a positive impact on Regional load factors and peak load management.

Potential and pending environmental regulations are studied to determine the potential impact on system reliability. Regulations that could challenge the economic or operational viability of a generation resource are studied to determine the likelihood of that regulation to create resource adequacy issues within the ERCOT Region. For example, should a particular environmental regulation restrain or restrict coal-fired generating stations, ERCOT would perform an economic and transmission system study to

[172] http://www.ercot.com/mktrules/guides/procedures.

[173] Section 5 of the ERCOT Operating Guides: http://www.ercot.com/mktrules/guides/operating/.

determine the reliability implications to ERCOT given the proposed limitations to an existing resource or group of resources. One such study[174] has recently been completed to determine the reliability implications of the following proposed regulations:

- Clean Water Act (Section 316(b)
- Title I of the Clean Air Act (new emissions standards for hazardous air pollutants)
- Clean Air Transport Rule (CATR)
- Coal Combustion Residuals (CCR) Disposal Regulations

A preliminary analysis of localized transmission system impacts included in the study indicates that the potential loss of 9,800 MWs of gas-fired generation would have impacts on transmission reliability in certain load center areas, likely requiring additional reactive devices and new import pathways into those areas. Redevelopment of existing generation sites in these areas with new generating units could reduce or delay the need for additional transmission infrastructure. In addition, ERCOT recently completed an assessment[175] of the proposed inclusion of Texas in the Cross State Air Pollution Rule (replaces CATR). The assessment determined that, if the rule is implemented as currently scheduled on January 1, 2012, then the current compliance plans for existing generators indicate 1,200 to 1,400 MW of generation would be unavailable year round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months. The unavailability of this generation would increase capacity insufficiency and the potential need for emergency actions including rotating outages, not only during the peak months but also during the off-peak months until retrofits or alternative resources are implemented. Project slow-downs, deferrals, cancellations, or other modifications to expected in-service dates are incorporated into the five-year planning models as appropriate. No project slow-downs, deferrals, cancellations, or other modifications are expected to impact reliability at this time.

Demand

The average annual growth rate for Total Internal Demand from 2011 through 2021 is 1.96 percent. Moody's base case economic forecast was used to provide forecasted non-farm employment values for 2011 through 2021. A normal weather year was determined based on actual weather data from 1996 through 2010. Reported peak demands represent the coincident demand for the ERCOT Region (Table 52).

Table 52: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	63,770	78,927	15,157	1.96%	23.8%
Net Internal	62,286	76,864	14,578	1.93%	23.4%

[174] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf.

[175] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

The Texas Legislature recently passed SB1125 which requires utilities to provide Energy Efficiency programs sufficient to reduce peak demand by 0.4 percent.[176] The incremental effects of this level of reduction are included as Energy Efficiency (New Programs) in this assessment, to the extent that the effects are not already incorporated into the forecast. Current Energy Efficiency impacts are reported to the Public Utility Commission of Texas (PUCT) on an annual basis.

Load forecast sensitivities are created using 10-year historic weather conditions, resulting in extreme summer peaks that would be 5 percent and 15 percent higher forecasted peaks for summer and winter, respectively. Extreme winter events, such as those recently experienced in ERCOT during the winters of 2009/2010 and 2010/2011 winters, significantly increase load because more load centers experience the extreme weather.

Emergency Interruptible Load Service (EILS) is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "Firm" load, and also represents contractually committed interruptible load. Based on the methodology described in Section 2.4.4,[177] ERCOT anticipates that approximately 421 MW of EILS load can be counted upon during the 2011 summer peak, increasing by 10 percent per year, up to the regulatory maximum of 1,000 MW in 2021 (Table 53). Additionally, LRs providing Responsive Reserve Service (RRS) are projected to provide 1,063 MW of dispatchable, contractually committed (Load as a Capacity Resource) Demand Response during summer peak hours in 2011 and beyond.

Table 53: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**128**	**1,609**	**1,481**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	421	1,000	579
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	1,063	1,063	-
Total Dispatchable, Controllable Demand Response	**1,484**	**2,063**	**579**
Total Demand-Side Management	**1,612**	**3,672**	**2,060**

Neither Demand Response nor Energy Efficiency capacity is eligible to participate in the Texas Renewable Energy Credits program, which is authorized by Texas Statute as the implementation vehicle for the state's Renewable Portfolio Standard. ERCOT does not administer Energy Efficiency programs nor does it currently allow Energy Efficiency programs to participate in its wholesale markets.

ERCOT has implemented a new neural network-based demand forecasting model since the 2010 LTRA. The neural network-based model was developed for each weather zone (currently eight zones), each day type (weekday, weekend, holiday), and each hour, within a given month. Some of the variables

[176] http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=82R&Bill=SB1125.

[177] http://www.ercot.com/mktrules/nprotocols/current.

used in the neural network-based model include sunset time, maximum and minimum temperatures for the current, previous, and key days, as well as average monthly temperature.[178]

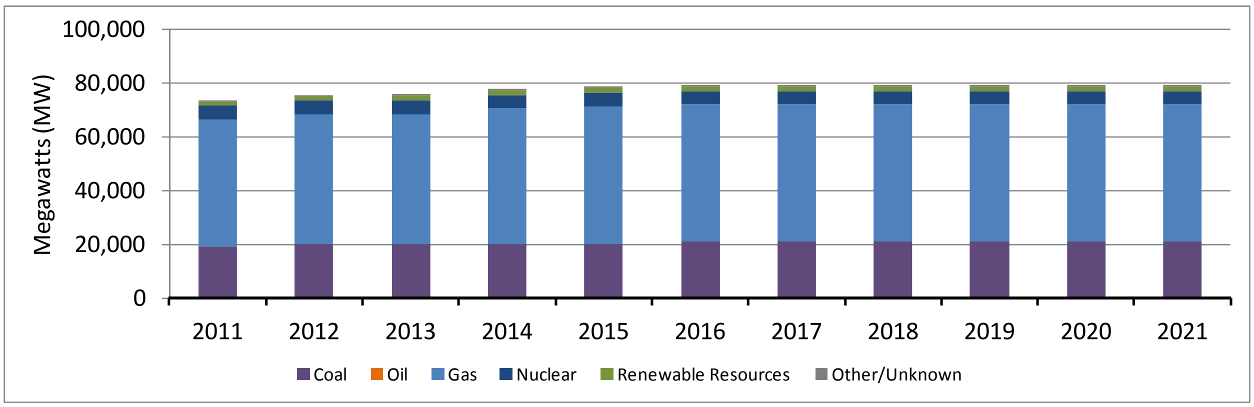
Generation

Generation values for the ERCOT Assessment Area are as follows:

- 72,905 MW of *Existing-Certain* generation
- 8,607 MW Existing generation consisting of installed capacity of wind (not counted toward Reserve Margins)
- 2,427 MW *Existing-Inoperable* generation
- 8,337 MW of *Future-Planned* net capacity to be in service by 2017
- 4,625 MW of *Conceptual* capacity in 2012 (19,827 MW in 2019)

On-peak capacity mix for the ERCOT Assessment Area through 2021 is shown below (Figure 74).

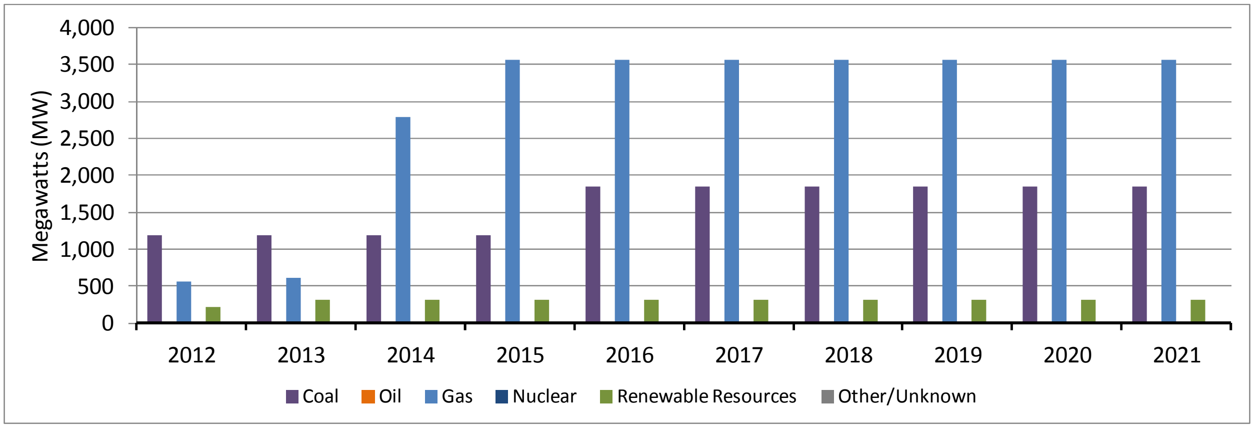
Figure 74: On-Peak Capacity Mix by Fuel Type



Before a new power project is included in Reserve Margin calculations, a binding interconnection agreement must exist between the resource owner and the transmission service provider. Additionally, thermal units must have an air permit issued by the appropriate state and Federal agencies that specify operating condition requirements. Future capacity that is expected to be available during the assessment period includes 3,558 MW of gas-fired generation, 1,845 MW of coal, 100 MW of biomass, 90 MW of solar photovoltaic generation, 1,240 MW of *Future-Other* and 1,504 MW of nameplate capacity from wind turbines (Figure 75). Of the 1,504 MW of nameplate wind capacity, only 131 MW, or 8.7 percent, contribute to Reserve Margin calculations.

[178] 2011 Long-term Load Forecast Model Description: http://www.ercot.com/calendar/2011/06/20110617-RPG.

Figure 75: Annual Net Capacity Change by Fuel Type



Conceptual capacity is comprised of projects that have progressed beyond feasibility studies and have progressed to the next stage of the interconnection study process. Of the 48,060 MW in this *Conceptual* category, 2,790 MW can be attributed to wind capacity that may count toward the Reserve Margin, 28,232 MW is the de-rated portion of the installed nameplate capacity of the wind, 787 MW to solar, 50 MW to biomass, with the remaining 16,201 MW to conventional fuel sources. Historically, 22 percent of projects in this category enter commercial operation, so this percentage is used to adjust the *Conceptual* capacity for the Adjusted Potential Resources calculation; however, past performance may not reasonably predict, by fuel type, the capacity that may eventually become operational.

ERCOT has existing wind generation nameplate capacity totaling 9,427 MW and that capacity is expected to increase to 10,931 MW by 2013; however, only 8.7 percent of the wind generation nameplate capacity is included in the *Existing-Certain* value used for Reserve Margin calculations, based on a 2007 study[179] of the effective load-carrying capability of wind generation in the region. Consequently, the expected on-peak capacity of wind generation ranges from the current value of 820 MW to 951 MW by 2013. The remaining existing wind capacity amount is included in the *Existing-Other* generation amount. Of all *Existing-Certain* resources, 92 MW include biomass with 100 MW of additional biomass included as *Future-Planned* capacity (Table 54).

[179] The 8.7 percent of wind installed capacity is based on a 2007 study of the effective load-carrying capability (ELCC) of wind generation. The 2010 LOLEv Study updated the ELCC calculation, but ERCOT did not adopt the revised ELCC for use in Reserve Margin calculations. The 2010 LOLEv Study: http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip.

Table 54: On-Peak Expected and Derated Renewable Resources

	Renewable Resource	2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	820	951	131
	Derated	8,607	9,980	1,373
	Wind - Total Nameplate Capacity	**9,427**	**10,931**	**1,504**
Solar	Expected	15	105	90
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**15**	**105**	**90**
Hydro	Expected	568	568	-
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**568**	**568**	**-**
Biomass	Expected	92	192	100
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**92**	**192**	**100**

Although no significant amount of additional distributed generation or behind-the-meter generation has been planned, ERCOT expects increasing distributed solar installations and is currently conducting studies to determine the best methods to incorporate this variable resource into the generation mix.

Capacity Transactions

ERCOT has interconnections through two asynchronous ties with the Southwest Power Pool (SPP) in 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 capability, 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 process to identify any import/export limitations.

ERCOT is a separate interconnection with only asynchronous ties to SPP and Mexico's Comisión Federal de Electricidad (CFE) and does not share reserves with other Regions. There are two asynchronous direct current (DC) ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 286 MW of transfer capability. ERCOT does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements with CFE and with American Electric Power (AEP) (the Balancing Authority on the SPP side of the SPP DC ties), it may request external resources for emergency services over the asynchronous ties or through block load transfers (Table 55).

For the assessment period, ERCOT has 458 MW of imports from SPP and 143 MW from CFE. Of the imports from SPP, 48 MW is tied to a long-term contract for purchase of Firm power from specific generation. The remaining imports of 410 MW from SPP and 143 MW from CFE represent one-half of the asynchronous tie transfer capability, included due to emergency support arrangements.

Table 55: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	598	598	598	598
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**598**	**598**	**598**	**598**
Exports	Firm	564	564	317	317
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**564**	**564**	**317**	**317**
	Net Transactions	**34**	**34**	**281**	**281**

SPP members' ownership stakes of 247 MW of a power plant located in ERCOT combined with a contract for 317 MW from another resource, results in a total export from ERCOT to SPP for 564 MW.

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

Transmission

The PUCT completed its Competitive Renewable Energy Zone (CREZ) transmission plan in 2008, resulting in bulk transmission in west Texas to provide solutions to existing and potential congestion and to enable the installation of more renewable generation in west Texas. The CREZ lines are expected to be in service by the end of 2013.[180]

Several other new 345 kV lines are under construction. Projects in the Dallas/Fort Worth, Corpus Christi, and San Antonio areas are planned to support reliability in these regions. New 345 kV lines are under construction to support major generation additions such as Oak Grove and Las Brisas Energy Center. A New 345 kV Switching Station, Zenith, and two new 345 kV lines from Fayetteville to Zenith are under construction to relieve thermal and voltage stability constraints in the Houston Area. There are no reliability concerns in meeting target in-service dates of the transmission projects. Operational procedures to maintain reliability will be implemented if unforeseen delays occur in these or other planned projects.

The ERCOT Region does not have any known transmission constraints that are expected to significantly impact reliability.

Other significant substation equipment installed or planned for the ERCOT Region includes:

- 250 MVAr Shunt Reactors for Brown Switch (CREZ related)
- 150 MVAr Shunt Reactor at Scurry County South Switch (CREZ related)
- 150 MVAr Shunt Reactor at Dermott Switch (CREZ related)

[180] http://www.texascrezprojects.com/default.aspx.

- 150 MVAr Shunt Reactor at Central Bluff Switch (CREZ related)
- 160 MVAr Shunt Capacitors at Killeen Switch (CREZ related)
- 200 MVAr Shunt Reactor at Graham Switch (CREZ related)
- Parkdale SVC (UVLS related)

Operational Issues

There are no known major facility outages that would significantly impact reliable operations expected over the next year's assessment period. If any issues arise, the outage coordination process addresses outages as well as potential constraints. If constraints are identified, remedial action plans or mitigation plans will be implemented to provide for preemptive or planned responses to maintain reliability. Interregional transfer capabilities are not generally relied upon to maintain transmission reliability and address capacity shortages, although emergency support arrangements are in place which provide for mutual support over the asynchronous ties or through block load transfers.

ERCOT can procure additional resources as needed in addition to Regulation Service, Non-Spin Reserves and Responsive Reserve Service (RRS). In the event that peak demands are expected to exceed all available generation and operating reserves, ERCOT will implement its EEA plan, as described in Section 6.5.9.3.4 (2) of the ERCOT Protocols[181] and Section 4.5 of the ERCOT Operating Guides.[182] The EEA plan includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the asynchronous ties, and ISO-instructed demand reduction.

Along with the impacts of the CSAPR (described above) there are known environmental restrictions or regulatory restrictions that are currently expected to significantly impact reliable operations expected over the assessment period. ERCOT performed a study[183] of the impacts of several pending EPA regulations, based on current understanding of the potential regulations, which showed that approximately 9,800 MW of generation could be retired in certain scenarios considered. The impact of these regulations to reliability will depend significantly on the implementation requirements and timeframe. If the current severe drought continues into 2012, there is a risk of significant resource unavailability. Generators are taking available steps to mitigate this risk.

ERCOT has procedures and existing processes in place to integrate variable resources into its operating practices. The Emerging Technologies Working Group has been established to track issues[184] and make recommendations regarding the integration of new technologies, particularly variable resources.

There are no anticipated reliability concerns resulting from high-levels of Demand Response resources. ERCOT limits the Demand Response participation of LR at 50 percent of the hourly RRS procurement, for which the minimum requirement is 2,300 MW. Load Resources are deployed automatically via UFR in

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

[182] http://www.ercot.com/mktrules/guides/operating/current.

[183] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf.

[184] http://www.ercot.com/content/meetings/tac/keydocs/2010/1104/15._ETIP_draft_v10_102210.doc.

response to frequency excursions below 59.7 Hz or through manual deployment during system emergencies such as EEAs. Finally, there are no anticipated reliability concerns with distributed resource integration at this time.

ERCOT has Operating Guides to address relay misoperations and the defined requirements for Registered Entities to follow in the event of relay misoperations. In addition, ERCOT has established the System Protection Working Group made up of ERCOT Market Participants with knowledge of relay operations to investigate relay misoperations and disseminate lessons learned.

Emerging and Standing Reliability Issues

Impact of Potential EPA Regulations

Timeframe

- The combined proposed environmental regulations are projected to be passed in final form as soon as November 16, 2011. Impact from the proposed regulation may be recognized in part as soon as January 2012, continuing through 2018.

Emerging or Standing Issue

- The impact of proposed environmental regulation on resource adequacy is a standing reliability issue of national interest that has been studied by NERC, ERCOT, and other concerned stakeholders.

Changes to Reference Case

- The EPA has proposed new regulations that, if implemented, may degrade the economic viability of certain generation resources. Specifically, the Clean Water Act (Section 316(b)), the Clean Air Act (new emission limits for Hazardous Air Pollutants), the Cross State Air Pollution Rule (CSAPR), and the Coal Combustion Residuals Disposal regulations may require retrofits, upgrades, or otherwise increase production costs to a point at which retirement of that (those) unit(s) may be more plausible than continued operation.

Projected Long-Term Impacts

- During the ten year horizon, generator owners whose cost of compliance is greater than or equal to the present value of the future predicted stream of revenue associated with a certain generator may opt to retire that unit. Preliminary ERCOT studies that did not include CSAPR suggest that legacy gas units are at highest risk of accelerated retirement.

Regional Reliability Impacts

- Accelerated generation retirements without accelerated development of new generation resources will further decrease the Reserve Margin within the ERCOT Region. The Reserve Margin in the ERCOT Region is forecasted to fall below the required 13.75 percent level in 2014 even without these accelerated retirements.

Resource Adequacy Considerations

- Preliminary ERCOT studies, which were performed prior to the issuance of the Cross State Air Pollution Rule and assumed implementation of the Clean Air Transport Rule, suggest that coal plants within the region should continue to be economically viable to operate, unless low natural gas prices and increased carbon emission fees occur with the pending regulations. Gas plants in the ERCOT Region, facing the imposition of closed-loop cooling tower requirements as a part of Section 316(b) of the Clean Water act, are more likely to see less than favorable economics for continued operation. ERCOT studies suggest that over 9800 MW of gas-fired generation near or around the Dallas and Houston areas may be impacted. In addition, ERCOT recently completed an assessment of the proposed inclusion of Texas in the Cross State Air Pollution Rule. The assessment found that, if the rule is implemented as currently scheduled on January 1, 2012, then generators' current compliance plans indicate that 1,200 to 1,400 MW of generation would be unavailable year round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months.

Transmission Adequacy Considerations

- If potential retirements occur as forecasted in ERCOT studies, then reactive support and/or new import paths would be required in the Dallas/Fort Worth and Houston metropolitan areas.

Resource Development Issues

- If potential retirements occur as forecasted in ERCOT studies, and market conditions do not attract incremental or replacement generation, then Reserve Margins within the ERCOT Region will not be satisfactory on a ten year horizon. The Public Utility Commission of Texas is holding the first of a series of workshops on resource adequacy. The first workshop, focused on the impacts from the EPA regulations, occurred on June 22, 2011.

Operational Impacts

- If potential retirements occur as forecasted in ERCOT studies and incremental or replacement generation is not constructed, then ERCOT will face lower Reserve Margins, decreased ramping capability, and increased transmission congestion. The unavailability of generation due to the Cross State Air Pollution Rule would increase capacity insufficiency and the need for emergency actions including rotating outages, not only during the peak months but also during the off-peak months until retrofits or alternative resources are implemented.

Additional Information

The proposed EPA regulations have the potential to expedite retirement of legacy generation units and exacerbate resource adequacy issues in ERCOT over the next 10-years:

- Clean Water Act – Section 316(b), regarding new requirements for cooling-water intake structures
- Clean Air Act – new emission standards for hazardous air pollutants
- Clean Air Transport Rule (CATR)
- Coal Combustion Residuals (CCR) Disposal regulations

These regulations threaten the economic viability of certain coal facilities and over 9800 MW of legacy gas generation. From a transmission perspective, such generation retirements would require new import paths and significant reactive support in the Dallas/Fort Worth and Houston metropolitan areas. From an operational perspective, accelerated retirements, as modeled, would further decrease the planning Reserve Margin in the ERCOT Region (currently projected to fall below the required 13.75 percent in 2014 without any additional retirements.) While the assessment above was based on CATR, the impacts of its replacement, the Cross State Air Pollution Rule, is expected to result in 1200-1400 MW of lignite-fueled generation being mothballed, and an additional 1800-4800 MW being unavailable during off-peak periods.

Reliable System Operations with Increasing Proportions of Renewable Resources[185,186]

Timeframe

- The designation of Competitive Renewable Energy Zones (CREZ), as well as a continuing trend of rapid development of renewable energy resources within the ERCOT Region is likely to continue over the next ten years. System Operations with increasing amounts of renewable energy present reliability challenges in longer term horizons.

Emerging or Standing Issue

- Reliable system operation with increasing amounts of renewable energy is a standing issue. This issue has become a core issue in the ERCOT region. The Emerging Technologies Working group has prepared a report that tracks issues and their solutions associated with renewable integration on an on-going basis. This issue had also been addressed in a study performed by General Electric: ERCOT Wind Impact / Integration Analysis.

Changes to Reference Case

- The resource mix in the LTRA will change with increasing amounts of renewable energy resources.

Projected Long-Term Impacts

- On a ten year horizon, ERCOT may have to modify its ancillary services procurement practices.

Regional Reliability Impacts

- Increasing amounts of renewable energy may require additional regulating capacity, including, but not limited to, increased system ramping capability, and/or additional resources to maintain system frequency in real time.

Resource Adequacy Considerations

- Studies are required to determine if additional thermal resources will need to be committed, or alternative transmission improvements are necessary to ensure reliable integration of increasing amounts of renewable energy resources.

Transmission Adequacy Considerations

- Currently, localized congestion and special protection systems within generation "pockets" of renewable/wind energy result in the curtailment of otherwise economic renewable energy. Competitive Renewable Energy Zones, or CREZ, created plans for 345 kV Transmission infrastructure to support the delivery of over 18,000MW of renewable / wind energy.

Resource Development Issues

- CREZ created plans for 345 kV Transmission infrastructure to support the delivery of over 18,000MW of renewable / wind energy. These upgrades are in design and construction and shall ease congestion and increase available capacity for incremental wind generation.

Operational Impacts

- Real time energy balance and frequency maintenance with an increasing proportion of wind energy and other intermittent resources on the ERCOT system will require updated ancillary service requirements.

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185 http://www.ercot.com/content/meetings/tac/keydocs/2010/1104/15._ETIP_draft_v10_102210.doc.

186 http://www.ercot.com/content/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_GE_Study.zip.

Additional Information

The ERCOT Region, with over 9000 MW of wind generation installed and an additional 1,500 MW currently planned (based on current interconnection agreements) over the next 10-years, must continue to refine its planning and operational procedures to ensure reliable integration of renewable resources. The Competitive Renewable Energy Zones (CREZ), currently under construction, was designed to have adequate transmission capacity for 18,000 MW of renewable energy. Should CREZ reach its designed capacity for renewable resources, ERCOT must continue to monitor the adequacy of its balancing and ancillary service procurement process under increasing proportions of renewable energy to load.

Assessment Area Description

The ERCOT Region is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority and Reliability Coordinator area. The ERCOT Region is a summer-peaking region with a population of about 22 million covering approximately 200,000 square miles. The ERCOT Region is responsible for about 85 percent of the electric load in Texas with an all-time peak demand of 65,776 MW set August 23, 2010). The Texas Reliability Entity (Texas RE) performs the regional entity functions described in the Energy Policy Act of 2005 for the ERCOT Region.

FRCC

Introduction

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating resources with transmission system deliverability throughout the long-term planning horizon. In addition, *Existing-Other* merchant plant capability of 575 MW is potentially available as future resources to FRCC members and others.

The transmission system within the FRCC region is expected to have adequate capacity to supply Firm customer demand and planned Firm transmission service. Operational issues could develop due to unplanned outages of generating units within the FRCC Region. However, it is anticipated that existing operating procedures, pre-planning, and training will adequately manage and mitigate these potential impacts to the bulk transmission system.

Reliability Assessment

The Florida Public Service Commission (FPSC) requires all Florida utilities to file an annual 10-year Site Plan that details how each utility will manage growth throughout the next decade. The data from the individual plans is aggregated into the FRCC Load and Resource Plan[187] that is produced each year and filed with the FPSC.

The FRCC 2011 Load and Resource Plan projects an average FRCC Reserve Margin of 23.2 percent during the summer peaks and a 29.3 percent Reserve Margin during the winter peaks between 2011 and 2021.[188] The 15 percent (20 percent for Investor Owned Utilities) Reserve Margin criteria required by the FPSC applies to the entire long-term planning horizon (Figure 76). The Reserve Margin calculation includes Firm imports into the region and does not include Energy-Only resources (excess merchant generating capacity that is not under a Firm contract with a load serving entity (LSE)). The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, emergency power contracts between SERC and FRCC entities can be used as available.

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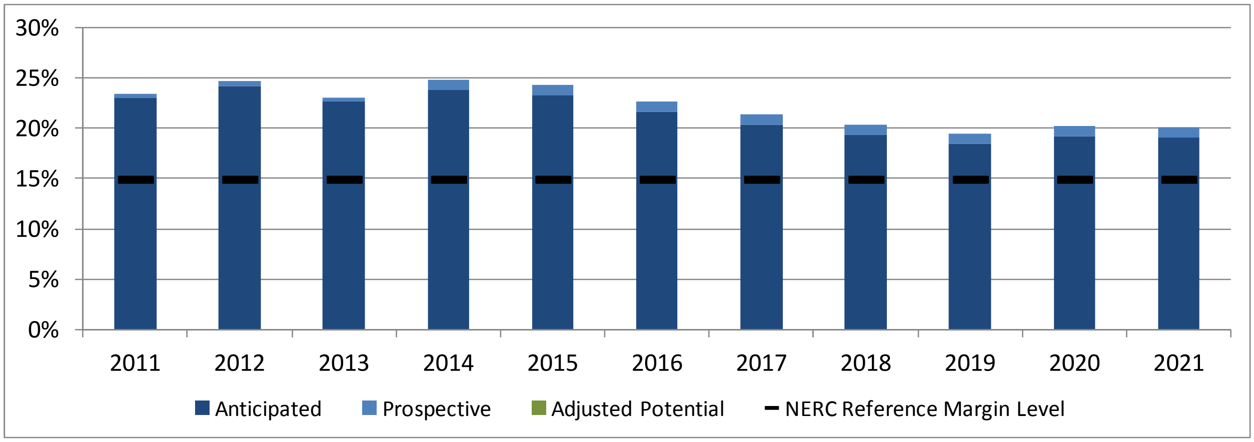
[187] https://www.frcc.com/Planning/Shared%20Documents/FRCC%20Load%20and%20Resource%20Plans/FRCC%202010%20Load%20and% 20Resource%20Plan.pdf.

[188] Values are based on the FRCC method of calculating Reserve Margin (treating CCDR as a demand reduction).

Figure 76: Annual On-Peak Planning Reserve Margins



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 resources will not be sufficient to serve forecasted loads. The objective of this study is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1 day in a given year is not exceeded.

The results of the most recent LOLP analysis conducted in 2009 indicated that for the "most likely" and extreme scenarios (*e.g.,* extreme seasonal demands; no availability of Firm and non-Firm imports into the region; and the non-availability of load control programs), the peninsular Florida electric system maintains an acceptable LOLP well below the 0.1 day per year criterion.

The amount of resources internal and external to the Region that are relied on to meet the minimum 15 percent Reserve Margin throughout the assessment period varies from 54,618 MW to 62,205 MW by 2020. The amount of resources external to the Region that are relied on to meet the Reserve Margin for the assessment period vary from 2,209 to 1,066 MW.

Some programs implemented as distributed generation include a Net Metering program and Feed-In-Tariff (FIT) program. Under the Net Metering Program, participants first consume the energy generated on-site, with any excess generation is fed into the distribution grid. Under the Feed-In-Tariff program all energy generated is fed directly into the utility's distribution network and none of the energy is consumed exclusively by the on-site customer. Renewable Energy Credits created by these programs become the custody of the host utility.

For capacity constraints due to inadequate fuel supplies, the FRCC State Capacity Emergency Coordinator (SCEC), along with the Reliability Coordinator (RC) have been provided with an enhanced ability to assess the status of Regional fuel supplies by initiating Fuel Data Status reporting by Regional utilities. This process relies on utilities to report actual and projected fuel availability, along with alternate fuel capabilities to serve 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 by FRCC and 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 integrated into an enhanced Regional Daily Capacity Assessment Process, along with various other coordination protocols. These processes help improve the accuracy of the Region's reliability assessments and ensure optimal coordination to minimize potential impacts of Regional fuel supply issues and/or disruptions to Bulk Electric System facilities and customers.

Fuel supplies continue to be adequate for the Region as exhibited during an unprecedented 2010 winter peak period that resulted in a new all-time coincident peak for the FRCC RC. Regional operators continue to develop mitigation strategies to minimize the effects of fuel supply impacts due to extreme weather during peak load conditions, including fuel supply and transportation diversity as well as alternate fuel capabilities. Fuel availability or supply issues have not been identified at this time. Based on current fuel diversity, alternate fuel capability and on-going fuel reliability analyses, the FRCC does not anticipate any fuel transportation issues that may impact capability during peak periods and/or extreme weather conditions.

Only Firm resources with Firm non-recallable contracts are considered in determining resource adequacy for the Region. Energy-Only resources are excluded and additional considerations are given to variable resources for energy projections, however, this capacity is excluded from Regional Reserve Margin calculations.

There are no planning changes needed throughout the assessment period due to the integration of variable or distributed resources. Demand Response is considered as a demand reduction. Entities within the FRCC use different methods to test and verify Direct Load Control Management (DCLM) programs, such as actual load response to periodic testing of these programs and the use of a time and temperature matrix, along with the number of participating customers.

No reliability impacts have been identified within the FRCC Region due to unit retirements. 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 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 minimal load to allow for voltage recovery. At this time no additional load is planned to be set for UVLS throughout the long-term planning horizon. The FRCC does not have any planned additional special protection systems or remedial action schemes throughout the long-term planning horizon.

Based on past operating experience with hurricane impacts to the fuel supply infrastructure within the Region, the FRCC developed a Generating Capacity Shortage Plan.[189] This plan can distinguish between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term generating fuel or availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (*e.g.,* hurricanes and abnormally high loads) in order to provide a more effective Regional coordination. The FRCC Operating Committee has also developed the procedure "FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers[190]" to enhance the existing coordination between the FRCC Reliability Coordinator and natural gas pipeline operators in response to FERC Order 698. In addition, the FRCC Operating Reliability Subcommittee, through its Fuel Reliability Working Group, continues to periodically review and assess the current fuel supply infrastructure in terms of reliability for generating capacity.

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL-001 – TPL-004. These studies include long range transmission studies and assessments, sensitivity studies addressing specific issues (such as extreme summer weather, off-peak conditions), interconnection and integration studies, and interregional assessments.

The results of the short-term (5-year) study for normal, single and multiple contingency analysis of the FRCC Region indicates 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.

In addition, the transmission expansion plans representing the longer-term study are typically under review by most transmission owners still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most transmission owners, these projects are not incorporated into the load flow databank models. As expected, the results show local loading trends throughout the FRCC Region, due to the uncertainties discussed above. No major projects requiring long lead times were identified.

Under Firm transactions, reactive power-limited areas can be identified during transmission assessments performed by the FRCC. These reactive power-limited areas are typically localized pockets with no impact on the bulk power system. The *FRCC Long Range Study 2011-2020* did not identify any reactive power-limited areas that would impact the Bulk Electric System through 2020. The FRCC Region has not identified the need to develop specific criteria to develop a voltage stability margin.

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

[190] FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers: https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FRCC%20Communications%20Protocols%20102207.pdf.

FRCC transmission owners evaluate new technologies such as Flexible AC Transmission System (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 within the Region. FRCC transmission owners are considering enhancements to existing transmission planning tools (*e.g.,* enhancements to existing software and new software) to address the expected planning needs of the future.

Entities within the FRCC Region may consider a wide range of programs to be Smart Grid programs. For example, some entities have been implementing programs that provide operational flexibility to minimize the number of customers potentially impacted during a distribution outage or manage distribution level feeder voltage control. A large number of Florida entities are in the process of installing two-way communication smart meters that will provide new information to the customers and allow for enhanced use control during peak times. Other entities have added extensive Demand Response programs, including smart thermostats and advanced load control systems for commercial customers.

Load serving projects can be delayed, deferred or cancelled in response to the latest load forecasts. Load forecasts have been reduced to reflect the anticipated economic conditions throughout the FRCC region for the planning horizon. However, there are no expected impacts on reliability through 2020 due to the degraded economic conditions within the Region.

Demand

The 2011-2021 Total Internal Demand forecast for the FRCC Region is projected to have a compounded average annual growth rate of 1.42 percent (Table 56).

Table 56: On-Peak Demand

Demand	2011 (MW)	2021 (MW)	Total Growth (MW)	Average Annual Growth Rate (%)	Total Assessment Period Change (%)
Total Internal	46,091	53,842	7,751	1.42%	16.8%
Net Internal	42,945	50,056	7,111	1.40%	16.6%

FRCC entities use historical weather consisting of at least 20 years of data for the weather assumptions used in forecasting models. Historically, the FRCC can experience high-demand days in both the summer and winter seasons. Weather and temperature variations typically differ from the "normalized" weather assumptions used to develop the individual utility forecasts. In Florida, this is much more pronounced for the winter months compared to the summer months. Therefore, this weather volatility caused a significantly larger number of over-forecast occurrences because since 1999 there has been only two years (2003 and 2010) with normal or colder than normal winter seasons for Florida. However, because the Region is geographically located in a subtropical area, a greater number of high-demand days normally occur during the summer. As such, this report will address the summer load values.

Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region non-coincident forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the Region level. The Regional non-coincident forecast is the basis for the evaluation of adequate levels of resources to meet Reserve Margin requirements. FRCC entities plan so that systems will meet the Reserve Margin criteria under both summer and winter peak demand conditions.

There are a variety of Energy Efficiency programs implemented by entities throughout the FRCC region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (*e.g.,* air conditioning, water heater, heat pumps, refrigeration) and lighting rebates.

The 2011 long-term forecast includes the effects of 2,520 MW of potential demand reductions from the use of Direct Control Load Management programs and 626 MW from interruptible demand through 2021 (Table 57). Total Demand-Side Management in FRCC is projected to increase by 640 MW during the assessment period.

Table 57: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	-	-	-
Non-Controllable Demand-Side Management	-	-	-
Direct Control Load Management	2,520	3,103	583
Contractually Interruptible (Curtailable)	626	683	57
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**3,146**	**3,786**	**640**
Total Demand-Side Management	**3,146**	**3,786**	**640**

Demand Response is considered as a demand reduction. Entities within the FRCC use different methods to test and verify DCLM programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix, along with the number of participating customers.

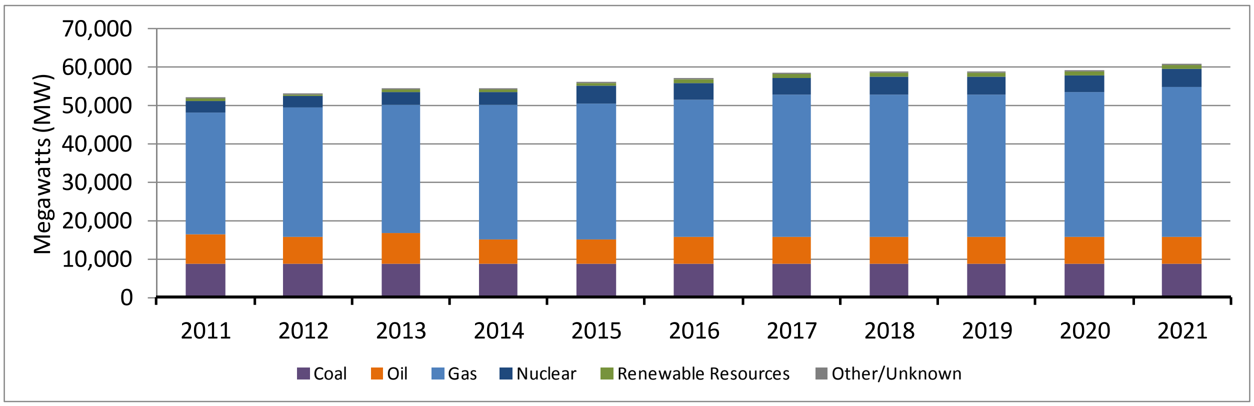
Regarding state Renewable Portfolio Standards (RPS), a draft rule was submitted by FPSC staff to the Florida Legislature for consideration; however, no RPS currently exists for the state. Projections incorporate demand impacts of new Energy Efficiency programs. Each LSE within the FRCC treats Demand Side Management program as demand reduction (not as a capacity resource).

Projected Regional demand is primarily driven by the variability of weather and economic assumptions. Currently, the FRCC is actively evaluating alternative methodologies to examine potential variability in projected demand due to weather, economic, or other key factors. The FRCC is working to develop regional bandwidths based on hourly load shape curves for the Region. The purpose of developing bandwidths for 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 fuel and electricity prices.

Generation

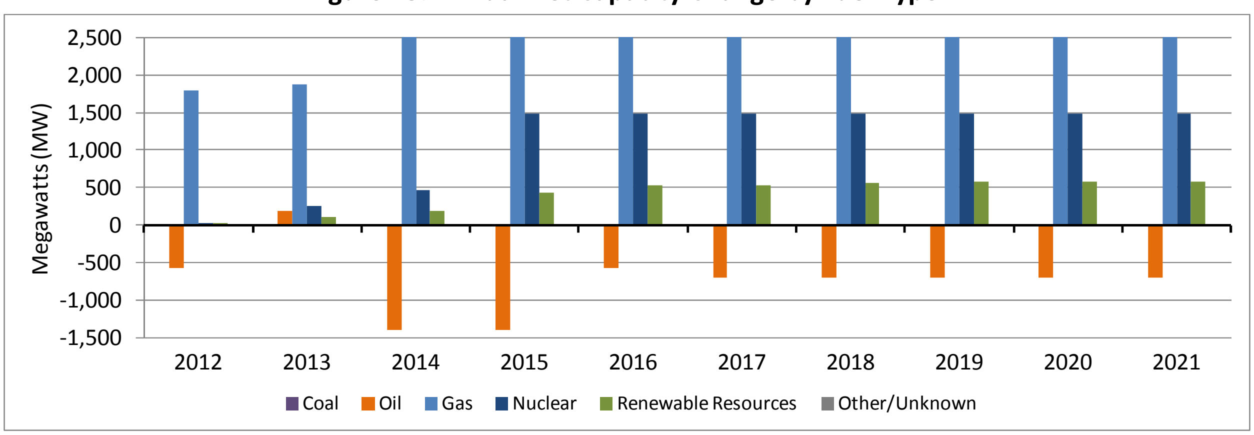
FRCC supply-side resources considered for this long-term assessment are categorized as *Existing-Certain*, *Existing-Other* and *Existing-Inoperable*. The annual on-peak capacity mix by fuel type for the FRCC Assessment Area through 2021 is shown below (Figure 77).

Figure 77: On-Peak Capacity Mix by Fuel Type



The net change in capacity by fuel type for the FRCC Assessment Area through 2021 is shown below (Figure 78).

Figure 78: Annual Net Capacity Change by Fuel Type



The FRCC Region counts on 50,201 MW of *Existing-Certain* resources, of which 44 MW are hydro and 362 MW are Biomass. Potential solar capacity is projected to increase from 47 MW to 63 MW during the assessment period (Table 58); however, most of this capacity is derated with only a small portion considered as a Firm resource, available during peak demand, with the remainder being used as an Energy-Only resource. *Existing-Other* merchant plant capability of 575 MW is potentially available as *Future-Planned* resources.

Table 58: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	-	-	-
	Derated	-	-	-
	Wind - Total Nameplate Capacity	**-**	**-**	**-**
Solar	Expected	4	10	6
	Derated	43	53	10
	Solar - Total Nameplate Capacity	**47**	**63**	**16**
Hydro	Expected	44	44	-
	Derated	11	-	(11)
	Hydro - Total Nameplate Capacity	**55**	**44**	**(11)**
Biomass	Expected	362	938	576
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**362**	**938**	**576**

There are a total of 2,846 MW of *Existing-Inoperable* resources for 2011. Approximately 565 MW of this capacity is being removed for plant modernization, 849 for unit repairs, while the balance of the capacity includes mostly older less efficient generating capacity being placed into operational standby[191] until forecasted loads resume to pre-2007 recessional levels. A net total of 1,271 MW of *Future-Planned* resources are projected for 2011. By 2020, *Future-Planned* net resources are expected to be 8,351 MW, of which 485 MW is Biomass, with solar resources accounting for 5.6 MW of Firm capacity.

FRCC entities have an obligation to serve, as reflected within each entity's 10-Year Site Plan, filed annually with the FPSC. FRCC entities consider all future capacity resources as "Planned" and included in Reserve Margin calculations.

One member has incorporated photovoltaic capacity as distributed generation (DG) in the long-range planning forecasts, and has committed to expanding the Feed-In-Tariff program by 4 MW per year through 2016. Photovoltaic capacity and energy generated under the Feed-In-Tariff program is supplied directly to the utility's network where a fixed portion of the DG is categorized as a Firm resource.

Capacity Transactions

The FRCC Assessment Area does not consider Expected or Provisional purchases or sales as capacity resources in the determination of the Region's Reserve Margin. The Firm interregional imports vary from 2,209 to 1,066 MW throughout the assessment period (Table 59). These imports have Firm transmission service to ensure deliverability. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between SERC and FRCC members.

[191] Generating resources that are out-of-service and cannot be brought back into service to serve load during peak demand.

Table 59: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	2,209	1,066	2,215	1,072
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**2,209**	**1,066**	**2,215**	**1,072**
Exports	Firm	143	143	-	-
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**143**	**143**	**-**	**-**
Net Transactions		**2,066**	**923**	**2,215**	**1,072**

The FRCC Region has 143 MW of generation under Firm contract to be exported during the summer into the SERC-SE Assessment Area throughout 2021. These sales have Firm transmission service to ensure deliverability in the SERC region.

Transmission

There are 45 miles of 230 kV transmission lines under construction as of January 1, 2011. Presently, there are 374 miles of planned transmission lines identified throughout the long-term planning horizon. Specifically, a major 13 mile, 230 kV transmission line is projected to be in-service for 2013 in Central Florida.

Increased west-to-east flow levels across the Central Florida metropolitan load areas may cause transmission constraints in Central Florida, requiring remedial actions schemes, depending on system conditions. Permanent solutions have been developed and are being implemented. In the interim, remedial operating strategies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability. No other significant substation equipment (SVC, FACTS controllers, HVdc, etc.) additions are expected through the remainder of the assessment period.

Operational Issues

There are no existing or potential significant systemic outages scheduled during seasonal peak periods through 2021. Scheduled transmission outages are typically performed during seasonal off-peak periods to minimize impacts to the bulk power system.

The FRCC Region maintains a minimum 15 percent Reserve Margin to account for higher than expected peak demand due to weather or other uncertainties. In addition, there are operational measures available to reduce the peak demand such as the use of interruptible or curtailable load, Demand-Side Management (HVAC, Water Heater, and Pool Pump), Voltage Reduction, customer stand-by generation, emergency contracts, and unit emergency capability.

There is the potential for serious impacts to reliability due to regulatory restrictions from pending Environmental Protection Agency (EPA) initiatives including:

- Proposed rules on coal combustion residuals and products under Resource Conservation Recovery Act (RCRA)
- Waste water discharge regulation under the Clean Water Act (CWA)
- Cooling water intake structures under CWA section 316(b), Clean Air Act (CAA)
- Maximum Achievable Control Technology (MACT) rulemakings for mercury and other hazardous air pollutants (HAPS)
- Cross State Air Pollution Rule (CSARP -CAIR replacement rule)
- New Ambient Air Quality Standards (AAQS) for fine particulate matter (PM2.5) sulfur dioxide (SO2), nitrogen dioxide (NO2) and ozone
- Regulation of greenhouse gases (GHG) under the Clean Air Act (CAA)

These and a series of other laws can potentially impact reliability, especially considering the combined impacts of several new policies. Consequently, entities may face challenges in scheduling the required overlapping maintenance outages of major fossil generating units as well as the planning retirements for existing units.

No operational changes are needed due to the integration of variable resources through 2021 unless new mandates require the addition of a significant amount of variable resources that could have the potential to significantly impact reliability. No operational changes are expected due to the integration of distributed resources through 2021.

Entities within the FRCC are taking many steps to reduce protection system misoperations whether by a relay or an auxiliary protective device. One major step is to improve protection system maintenance documentation and record keeping programs as well as upgrade protection systems as part of capital improvement programs for certain FRCC entities. In addition, FRCC entities thoroughly investigate misoperations to determine the root cause when practical. Results of individual entity reviews are discussed and made available to appropriate FRCC entities to share potential lessons learned.

Emerging and Standing Reliability Issues

Impact of Potential EPA Regulations

Timeframe

- Short-term.

Emerging or Standing Issue

- Emerging.

Changes to Reference Case

- The reference case resource capacity will decrease to account for potential unit retirements and/or unit derates potentially impacting reliability.

Projected Long-Term Impacts

- Generation capacity mix may change during the 10-year horizon in response to the implementation of the potential EPA regulations.

Regional Reliability Impacts

- There may not be sufficient time to replace generation capacity impacted by the implementation of the potential EPA regulations during the same time period. In addition, unit upgrades needed to comply with the potential EPA regulations may not be implemented in the expected time frame requiring the unit to be out of service for an extended period of time.

Resource Adequacy Considerations

- Resource capacity can be significantly impacted based on the final EPA regulations.

Transmission Adequacy Considerations

- Impacts are expected to be minor unless potential replacement capacity requires new transmission.

Resource Development Issues

- Availability of materials required to retrofit units as needed.

Operational Impacts

- Dispatch patterns may change under certain conditions. Additional studies can provide assistance to help develop appropriate mitigation strategies to minimize the potential impact on daily operations.

Additional Information

There are potential impacts to reliability due environmental restrictions. The combination of these proposed rules may challenge outage coordination and retrofits schedules which may require overlapping maintenance outages of major fossil generating units as well as the retirement of existing units. These proposed rules can impact resource adequacy in the near term due to the potential lack of materials needed to retrofit existing resources. In addition, operational impacts associated with changes in dispatch patterns under certain conditions may occur. In order to address these concerns, entities within the FRCC Region are closely monitoring legislation related to EPA initiatives and evaluating potential options.

Assessment Area Description

FRCC's membership includes 31 Regional Entity Division members and 24 Member Services Division members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. The FRCC Region is typically summer peaking and divided into 10 Balancing Authorities. FRCC has registered 73 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.[192]

[192] https://www.frcc.com/default.aspx.

MISO

Introduction

MISO's Planning Authority Region covers 750,000 square miles, which includes 13 states. MISO's Midwest Energy and Operating Reserves market includes 347 market participants who serve over 40 million people. MISO experiences its annual peak during the summer.

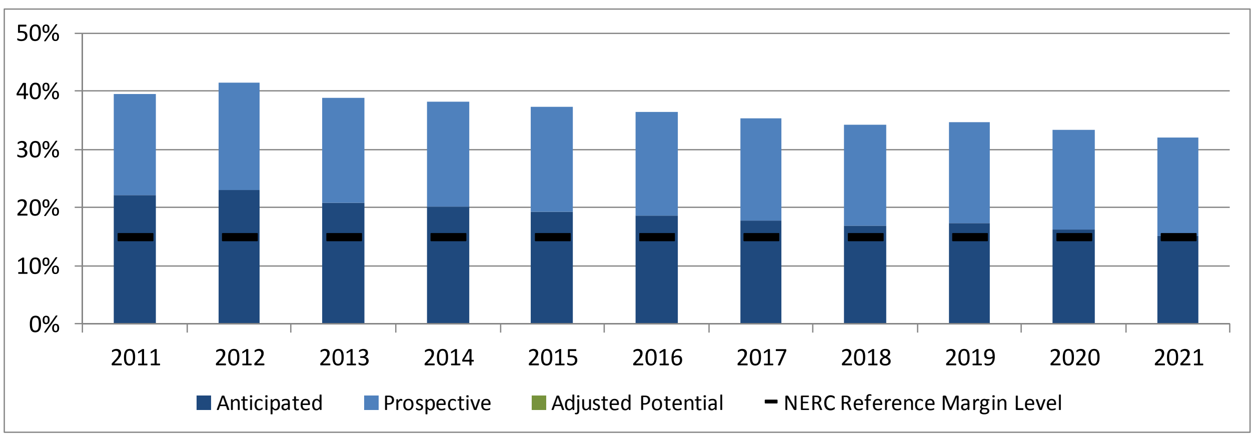
MISO market participants use the Module E Capacity Tracking (MECT) tool to submit its forecasted demand and resources at each Load Commercial Pricing Node. These forecasts are then aggregated to determine the MISO regional demand, generation, and Reserve Margin forecasts. The latest MISO Commercial Model is used for calculating *Existing-Other* capacity resources.

Coordination amongst several MISO departments occurs to provide accurate forecast information for each section of this report. Load and resource forecasts are provided in the demand and generation sections, and transmission and operational concerns are identified in subsequent sections of this report.

Reliability Assessment

The goal of a Loss of Load Expectation (LOLE) study is to determine a level of reserves which ensures that the probabilities for loss of load within the MISO system over each integrated peak hour for the planning period sum to 1 day in 10-years or 0.1 days per year, or less.[193] According to the 2011 LOLE study, the Planning Reserve Margin (PRM) requirement calculated for MISO is 17.4 percent of MISO's Net Internal Demand[194] of its market area for the 2011 planning year (Figure 79).

Figure 79: Annual On-Peak Planning Reserve Margins



The 2011 PRM increased by 2 percent from 2010. The main drivers for the change were from increases in system forced outage rates and forecast uncertainty. However, due to the diversity of the MISO

[193] http://www.misoenergy.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf.

[194] MISO Net Internal Demand is Total Internal Demand less Direct Control Load Management and Interruptible Load.

system, MISO Load Serving Entities (LSEs) are only required to carry 12.1 percent reserves to meet the Reserve Margin requirement, as opposed to the system PRM of 17.4 percent.[195]

The target Reserve Margin requirement for 2011 Planning Year is 15 percent and is applied through 2021. The Reserve Margins projected through the assessment timeframe varies with projected changes in the membership. Evaluating the impact of *Existing-Certain* resources, net Firm transactions, and *Future-Planned* resources and future unit contractions from 2012 to 2021 on resource adequacy, the MISO Anticipated Capacity Resources Reserve Margin ranges from 15.2 to 23.2 percent. The MISO 17.4 percent PRM is met until 2018 when it drops below the requirement. However, with all other resource supply categories (*Existing-Certain*, *Future-Planned*, and *Conceptual*) included, the forecasted Reserve Margin for MISO exceeds the target Reserve Margin requirements by 16 percent.

In addition to the 107,051 MW of *Existing-Certain* capacity resources, MISO forecast 4,894 MW of external resources will be available to serve its load from year-to-year. All these imports are Firm and fully backed by Firm transmission and Firm generation. Behind-the-meter generation is considered a capacity resource when calculating the MISO Reserve Margin. Due to the high reserve levels throughout this assessment period, it is unlikely that reliance on external support or reserve sharing will be an issue; however, extreme conditions could temporarily necessitate the need for all available resources.

MISO uses the Energy Information Administration (EIA) fuel forecasts to identify any system wide fuel shortages. There were none projected for 2012 and beyond. In addition, MISO's Independent Market Monitor submits a monthly report to the MISO's Board of Directors, which covers fuel availability and security issues. During the operating horizon, MISO relies on market participants to anticipate reliability concerns related to the fuel supply or fuel delivery. Since there are no requirements to verify the operability of backup fuel systems or inventories, supply adequacy and potential problems must be communicated appropriately by the market participants to enable adequate response time. MISO does not analyze energy-only resources in the resource adequacy assessment; however, transmission-limited resources are analyzed through Module E when determining *Existing-Certain* capacity MWs.

MISO continues to work toward integrating large amounts of wind generation needed to meet individual state Renewable Portfolio Standards (RPS) within its footprint. MISO completed the Regional Generation Outlet Study (RGOS) to develop a set of regionally coordinated transmission projects that seek to meet both the individual state's RPS and LSE renewable energy goals, while minimizing customer costs. The RGOS evaluated a number of other robust transmission expansion plans, some of which are expected to be in-service within the next 10-years.[196] The candidate Multi-Value Projects (MVP) Portfolio #1 study is underway to move a subset of the RGOS plan to approval and implementation. Due to the intermittent nature of wind, there is difficulty in projecting the wind capacity available on-peak. MISO determines a maximum wind capacity credit using the Equivalent Load Carrying Capacity (ELCC) metric, commonly used by National Renewable Energy Laboratories (NREL). This capacity credit is used

[195] Refer to Table 3-4 of the 2011 LOLE Study Report for a comparison of Planning Year 2011 PRM to last year's PRM.

[196] https://www.misoenergy.org/Planning/Pages/RegionalGenerationOutletStudy.aspx.

for wind generation and Loss of Load Expectation (LOLE) analyses. For the 2011-2012 planning year, MISO employed an average wind capacity credit of 12.9 percent.

MISO currently separates Demand Resources into two separate categories, Direct Controlled Load Management and Interruptible Load. If peak demands are higher than expected, MISO can call the Local Balancing Authorities (BAs) to deploy Demand Response, however, the local BAs also have the option to independently deploy Demand Response depending on availability. As these Resource Adequacy processes continue to evolve within MISO, additional methods may be developed regarding verification of Demand Response resources.

There are currently no planned or proposed unit retirements projected to significantly reliability; however, the combined impacts of potential environmental regulations will be discussed further in the Emerging Issues section of this assessment. MISO has also implemented procedures for analyzing unit retirements that would identify any must-run units and provides necessary mitigation plans. Accordingly, any potential unit retirements that may cause reliability concerns will be required to operate under a System Supply Resource (SSR) agreement with MISO until alternatives (*e.g.,* generation re-dispatch, system re-configuration, and transmission reinforcement acceleration) become available.

There are currently no reported plans for the installation of any additional MISO Under Voltage Load-Shedding (UVLS) schemes, special protection systems (SPS), or remedial action schemes (RAS) in lieu of planned bulk power transmission facilities within the MISO Assessment Area. Currently, it is the responsibility of MISO members and corresponding Regional Reliability Organizations (RRO) to implement specific schemes or protection systems to respond to a loss of load event. MISO plans for the occurrence of catastrophic events by applying each generator's forced outage rate (which includes these types of events) in the calculation of the planning Reserve Margin.

MISO conducts an annual Transmission Expansion Planning (MTEP)[197] and Long-Term Assessment[198] that focuses on the reliable and efficient electricity expansion during a 10-year time frame while also complying with all relevant NERC reliability standards. The MTEP identifies solutions to meet transmission needs and to create value opportunities over the next decade and beyond via the implementation of a comprehensive planning approach[199]. Ultimately, the objective is to identify projects that:

- Ensure reliability of the transmission system
- Provide economic benefit, such as increased market efficiency
- Facilitate public policy objectives, such as the integration of renewable energy
- Address other issues or goals identified through the stakeholder process

The MISO Long-Term Assessment evaluates demand, capacity, and Reserve Margins including a risk

[197] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx.

[198] https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacy.aspx.

[199] For a complete listing of all MTEP 10 related recommendations, see the Executive Summary section of the MTEP 10 report.

assessment which analyzes case studies while ensuring that LOLE requirements are met throughout the assessment timeframe.

MISO has not indentified any dynamic or static reactive power-limited constraints within its planning area, and currently does not have any criteria for a voltage stability margin.

MISO launched a 3-year program to install more than 150 high-tech devices that will monitor the state of the electrical grid 30 times per second, increasing the efficiency and reliability of power delivery.[200] The smart grid programs are part of Midwest ISO's agreement with the U.S. Department of Energy to implement synchrophasors, also known as phasor measurement units (PMUs), to more accurately measure voltage and current within the Eastern Interconnection. PMU measurements could increase available transmission and improve system-wide reliability, enhanced grid visualization, operational awareness, stability monitoring, state estimation, and after-the-fact analysis.

Pending environmental regulations on greenhouse gas emissions regulations could have a profound impact on MISO. These effects are being quantified through analysis of current environmental controls in place throughout MISO and the possibility for economically viable upgrades. This analysis is currently underway and will feed into other planning process within MISO as results are achieved.

There are no reported project slow-downs, deferrals, cancellations which may impact reliability within the MISO Planning Authority footprint.

Demand

Demand forecasts as reported by network customers, are weather normalized using 50/50 forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50 percent chance the actual load will be either higher or lower than forecasted. Historically, reported load forecasts have been accurate, as each member has expert knowledge of their individual loads with respect to weather and economic assumptions.

To ensure the accuracy of LSE forecasts, MISO conducts after-the-fact analysis at the Commercial Pricing Node level. If MISO determines that an LSE under forecasts its demand, (after accounting for any actual weather conditions and other normalization adjustments during such month) the MISO will notify the LSE of the under forecast and request a written response, detailing the reasons for the under forecast. For under forecasts for one month between June 1 and September 30 of the same calendar year, or under forecasts for three consecutive months, MISO will inform the applicable state authorities of all under forecasts that are significant to an LSE's total forecast.[201]

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[200] https://www.midwestiso.org/AboutUs/MediaCenter/PressReleases/Pages/IntegrationofSmartGridTechnologyAchieved.aspx.

[201] https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2011/20110609/20110609%20SAWG %20June%202011%20Metrics%20Report.pdf.

The 2011 assessment, with contributions from First Energy or Duke Ohio and Duke Kentucky, resultes in a annual growth rate of 0.26 percent in Total Internal Demand from 2011-2021 (Table 60).

Table 60: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	98,068	100,928	2,860	0.26%	2.9%
Net Internal	90,249	93,109	2,860	0.28%	3.2%

An unrestricted non-coincident peak demand is calculated by summing the non-coincident monthly forecasts for each Load Serving Entities (LSE). Using historic market data, a load diversity factor was calculated by observing the individual peaks of each BA and comparing these values with the system peak. By taking the product of the diversity factor and the unrestricted non-coincident peak demand, MISO is able to estimate the Total Internal Demand.[202]

MISO currently bases its resource evaluation on the actual market peak and separates demand resources into two separate categories, Direct Controlled Load Management (DCLM) and Interruptible Load. The current and projected Interruptible load of 3,093 MW for this assessment is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The current and projected DCLM of 1,118 MW for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator (Table 61). DCLM is typically used for "peak shaving." MISO uses the industry standard 90/10 forecast, to project a high demand case, in order to reflect the potential variability in projected demand due to weather, economics, or other key factors.

Table 61: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011	2021	Total Change
	(MW)	(MW)	(MW)
Energy Efficiency (New Programs)	-	-	-
Non-Controllable Demand-Side Management	-	-	-
Direct Control Load Management	1,118	1,118	-
Contractually Interruptible (Curtailable)	3,093	3,093	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	3,608	3,608	-
Total Dispatchable, Controllable Demand Response	**7,819**	**7,819**	-
Total Demand-Side Management	**7,819**	**7,819**	-

MISO does not currently track Energy Efficiency; however, the impact of these programs may be reflected in individual LSE load forecasts. To account for uncertainties in load forecasts, MISO applies a

[202] This Total Internal Demand is used when comparing to the target Reserve Margin.

Load Forecast Uncertainty (LFU) with a probability distribution to consider a larger range of forecasted demand levels. The LFU is derived from variance analyses to determine how likely forecasts will deviate from actual load. The impacts of the recent economic recession have not resulted in any changes to either load forecasting methods or assumptions.

Generation

MISO projects that the capacity over this assessment's long-term timeframe is 107,051 MW for *Existing-Certain* capacity, 17,108 MW for *Existing-Other* capacity, and 1,850 MW for *Existing-Inoperable* capacity. It is important to note that *Existing-Certain* capacity does not account for *Future-Planned* unit contractions, specifically due to the exit of Duke Ohio and Kentucky in 2012. The on-peak projected capacity mix and annual net change by fuel type, through 2021 for the MISO Assessment Area are shown below (Figure 80 and Figure 81).

Figure 80: On-Peak Capacity Mix by Fuel Type

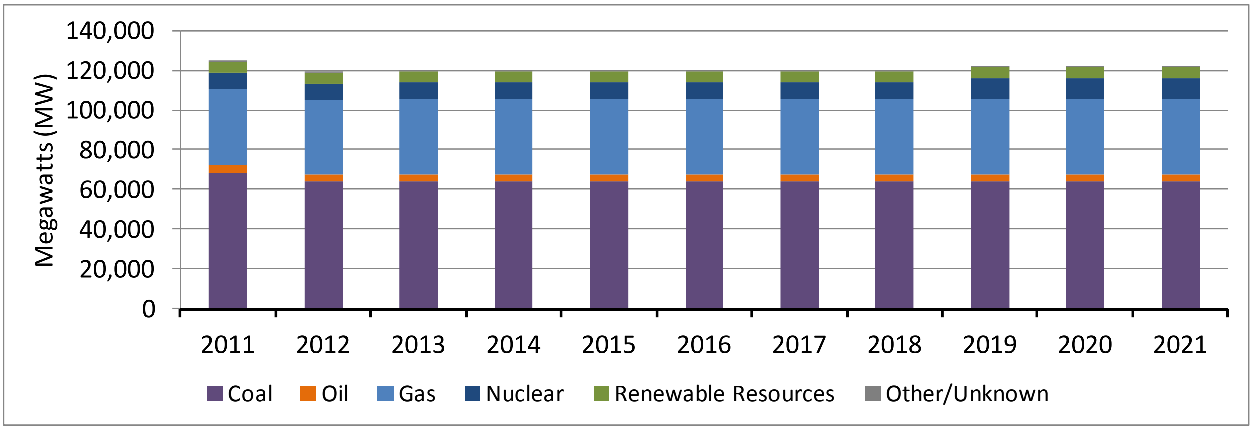
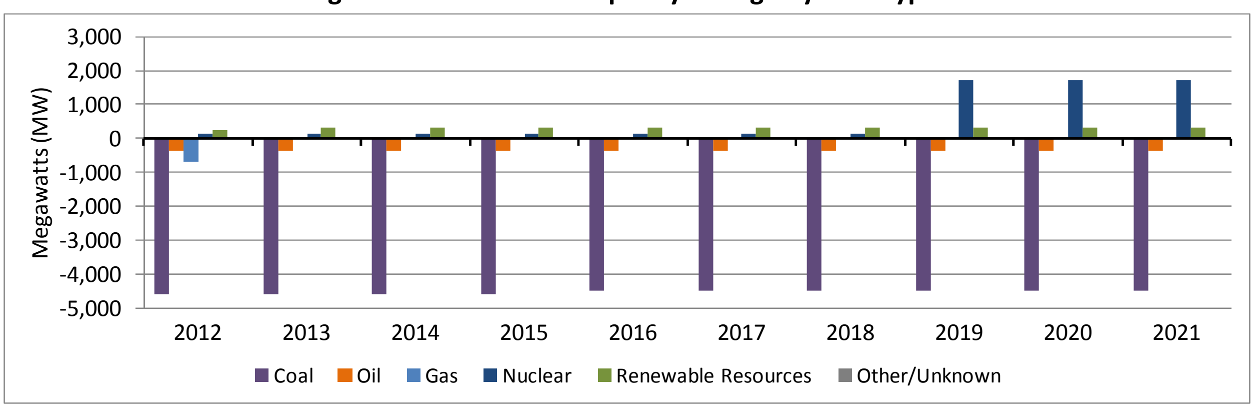


Figure 81: Annual Net Capacity Change by Fuel Type



Due to the intermittent nature of wind, it is difficult to project the wind capacity available on-peak; however, the MISO determines a maximum wind capacity credit using an Equivalent Load Carrying Capacity (ELCC), a metric commonly used by the National Renewable Energy Laboratory (NREL). MISO used the ELCC for wind generation and Loss of Load Expectation analyses. Wind shows an *Existing-Certain* capacity of 389 MW on-peak based on the 12.9 percent capacity credit for those resources committed as a Planning Resource capacity to MISO within the Module E Capacity Tracking (MECT) tool.

The wind capacity credit increased by 4.9 percentage points (8 percent was used for 2010) due to a methodology change in the ELCC metric and because of better wind performance in 2010 due to increased diversity (a new Iowa member was integrated in 2010 which provided an additional 1,407 MW of nameplate wind capacity). It is important to note that not all Existing wind capacity was committed in the MECT. The *Existing-Other* capacity for wind is 681 MW on-peak with a 7.7 MW derate. Biomass shows an annual *Existing-Certain* capacity of 496 MW on-peak.

Future nameplate wind capacity is expected to increase to 2,133 MW by end of 2021 with approximately 275 MW or 12.9 percent wind available at peak times based on the maximum wind capacity credit using an Equivalent Load Carrying Capacity (ELCC) metric. Future biomass capacity resources of 40 MW would be installed by end of the assessment period (Table 62).

Table 62: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	389	664	275
	Derated	7,683	9,542	1,858
	Wind - Total Nameplate Capacity	**8,072**	**10,206**	**2,133**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	717	717	-
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**717**	**717**	**-**
Biomass	Expected	496	536	40
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**496**	**536**	**40**

Conceptual nameplate capacity resources could account for a total of 2,910 MW by 2021 with 2,209 MW of wind resources, 9 MW of solar, 11 MW of biomass, and 681 MW of other resources. Approximately 285 MW or 12.9 percent of wind is available at peak times based on the maximum wind capacity credit using an Equivalent Load Carrying Capacity (ELCC) metric.

MISO uses *Existing-Certain* and Net Firm Transaction resources for reliability analyses and Reserve Margin calculations. A historical study of the Generation Interconnection Queue was undertaken to determine confidence factors based on fuel type and study status. MISO uses confidence factors to describe the probability a project with a specific Generation Interconnection Queue status will be built, and it is applied to a unit's summer rated capacity. The confidence factors used for this assessment are shown below (Table 63). A completed MISO Interconnection Agreement (IA) means that the project in the Generation Interconnection Queue has a higher likelihood of being interconnected. Others Queued are all other study statuses within the Generation Interconnection Queue.

Table 63: MISO Generator Interconnection Queue Confidence Factors

Fuel/Unit Type	Completed IA	Other Queued
Biomass	80.16%	19.03%
Biomass & Natural Gas	80.16%	19.03%
Coal	54.95%	13.67%
Combined Cycle	80.16%	19.03%
Gas	93.47%	31.44%
Hydro	100.00%	0.17%
Landfill Gas	80.16%	19.03%
Natural Gas	80.16%	19.03%
Nuclear	100.00%	4.63%
Wind	74.73%	6.88%
Wood	80.16%	19.03%
Solar	74.73%	6.88%

Once confidence factors are applied to the projects within the Generation Interconnection Queue, the units are categorized by *Future-Planned*, *Future-Other* and *Conceptual* resources.

There were no increases in registered behind-the-meter generation (BTMG) within MISO from the 2011 summer forecasted value of 3,608 MW. Registered BTMG is allowed to participate in the MISO market as a capacity resource; however, more BTMG exists within the MISO footprint. Total BTMG within MISO is in excess of 5,000 MW.

Capacity Transactions

MISO only reports Firm power imports (not exports) to the MISO market or reported interchange transactions into the MISO market. The forecast reflects approximately 4,894 MW of typical power imports from year-to-year (Table 64).[203] All these imports are Firm and fully backed by Firm transmission and Firm generation. No import assumptions are based on partial path reservations. There are no transactions with Liquidated Damages Contract (LDC) clauses or "make-whole" contracts that are included as Firm capacity. MISO does not intend to rely on outside assistance or external resources for emergency imports.

[203] 2010 summer peak power imports obtained from the MECT.

Table 64: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	4,894	4,894	-	-
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**4,894**	**4,894**	**-**	**-**
Exports	Firm	-	-	-	-
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**-**	**-**	**-**	**-**
	Net Transactions	**4,894**	**4,894**	**-**	**-**

Transmission

As of March 2011 MISO has 273 miles of greater than 100 kV transmission line under construction, 1,316 miles of greater than 100 kV planned transmission line expected to be in service within 5 years, 1,571 miles of greater than 100 kV planned transmission line expected to be in service within 10-years, all of which totaling 1,844 miles of new under construction or planned transmission expected to be in-service within the assessment period. These projects are anticipated to come into service during the 2011-2021 assessment period to enable reliable and efficient transmission service for the MISO region. There are no foreseeable reliability impacts from not meeting target in-service dates of planned transmission projects. MISO does not anticipate any existing, significant transmission lines or transformers being out-of-service through the assessment period. MISO does not have any transmission constraints that could significantly impact reliability.

Operational Issues

There is no foreseeable existing or potential systemic outages that may impact reliability during the next 10-years. Amongst other measures, MISO uses Transmission Loading Relief, binding constraints through the use of MISO's centrally controlled, security constrained economic dispatch (SCHED) as part of the Locational Marginal Prices (LMP)-based market, and reserve deployment as temporary operating measures to maintain reliability.

If peak demands are higher than expected, MISO will call the Local Balancing Authorities to deploy Load Modifying Resources, however, the Local Balancing Authorities also have the option to independently deploy Load Modifying Resources that they may have. Demand Response Resources are dispatched in merit order through the Security Constrained Economic Dispatch. MISO can also use Emergency procedures if peak demands are higher than expected. There are currently no environmental or regulatory restrictions that could potentially impact reliability. MISO plans on using intermittent dispatchable technology for the integration of variable resources in the future. There are currently no operational changes or concerns resulting from distributed resource integration. There is no anticipation for reliability concerns resulting from high-levels of Demand Response resources.

Emerging and Standing Reliability Issues

Integration of Variable Resources

Timeframe

- This issue has current concerns that will continue into the foreseeable future.

Emerging or Standing Issue

- This is an emerging issue that has been identified within MISO that may impact minimum generation events as well as potential operational issues around ramp rates to meet demand requirements on the system.

Changes to Reference Case

- Currently, MISO receives between 3 to 4 percent of its energy from intermittent resources. Because of state mandates and goals, this is expected to rise to around 13 percent of total system energy served (as of 2011 membership).

Projected Long-Term Impacts

- Within the ten-year horizon, it is expected that the MISO footprint will see around 12 percent of the total energy come from renewable resources.

Regional Reliability Impacts

- There are two primary concern associated with the integration of the intermittent resources:
  - Minimum generation events within the footprint, and
  - Maintaining appropriate ramp and operational reserves around resources.

Resource Adequacy Considerations

- Current concerns are focused towards operational needs. However, as the penetration of these resources grow, it will be important to monitor their contributions to resource adequacy and determine their effectiveness of contribution to meeting peak requirements.

Transmission Adequacy Considerations

- Interconnection of intermittent resources is generally handled through generation interconnection requirements. However, it is important that the transmission system is suitable to enable the solutions needed to meet potential issues on minimum generation or operational considerations.

Resource Development Issues

- MISO is attempting to bridge potential issues through its transmission cost sharing mechanism and Dispatchable Intermittent Resource classifications within the ISO/RTO.

Operational Impacts

- Intermittent resources may have an impact certain operational issues. To this extent, MISO has implemented evaluation and rule sets to help mitigate potential ramp and minimum generation issues.

Additional Information

Every state within the MISO footprint, except one, has either a renewable energy mandate or goal. It is expected that the primary source of new renewable energy will come from intermittent resources including wind and solar power. The integration of intermittent resources presents new challenges to the MISO footprint. The integration does not cause undo reliability issues on its own, but does continue the evolution of how the bulk power system is operated.

It is expected that the large penetration of the resources could impact many aspects of the system. As the penetration of the resources increase, their contribution to resource adequacy will also increase. This may introduce additional uncertainty in maintaining system resource reliability. Injection of new resources will have an impact on the transmission system and increase potential for congestion on the system. Intermittent resources also have an impact on the operation of the system generation fleet as resources will need to be dedicated in meeting the potential ramp and minimum generation issues that could occur.

It is expected that the development of the intermittent resources will occur throughout the MISO system. Although heavily concentrated in the western portion of the footprint at this time, more regional development will occur as local needs are met. Currently, development is focused around meeting the existing state renewable energy mandates. However, if additional regulations are pushed forward (clean energy standards, carbon reduction) more resources may be required. Additionally, economic factors may increase the amount of intermittent resources found on the system such as higher gas prices or lower construction costs for the intermittent resources.

Current intermittent resource penetration within the MISO footprint has had minimal impact on reliability issues. However, the expected challenges to come are being evaluated and mitigated within the MISO construct. First, the existing energy market manages transmission congestion from all resources. The ancillary services market provides market products to help manage the operational issues that may occur. Finally, the implementation of MISO’s FERC-approved Dispatchable Intermittent Resources (DIR) initiative allows resources like wind to be treated like any other generation resource in the market and, for the first time, participate in the region’s real-time energy market. Now wind can automatically be dispatched up to a forecasted limit based on an offer price and system conditions. This enables wind to submit offers and receive dispatch instructions rather than be manually curtailed when transmission constraints limit renewable energy generation to reach the broader market region.

Environmental Regulations

Timeframe

- This issue is expected to have impacts in the 6-10 year time frame.

Emerging or Standing Issue

- This is an emerging issue that the MISO is currently evaluating along with other entities within the industry.

Changes to Reference Case

- It is expected that coal resources currently available may not be available in the future because it is uneconomic to retrofit capacity to meet future environmental requirements.

Projected Long-Term Impacts

- Near-term issues may put pressure on current resource adequacy reserves.

Regional Reliability Impacts

- This will have a direct impact on resource adequacy issues, as well as potential impacts on energy market prices.

Resource Adequacy Considerations

- Various studies have shown potential impacts on resource adequacy because of retrofits required to meet new environmental regulations or retirements because retrofits may be an uneconomic decision for generation asset owners.

Transmission Adequacy Considerations

- Transmission adequacy has not been fully fleshed out within MISO. However, it is expected that some units that may be likely candidates for retirement will have negative impacts on transmission adequacy.

Resource Development Issues

- It is expected that resource development will occur to meet resource adequacy needs. However, it is not certain that resources that minimize cost to end-users will be available.

Operational Impacts

- There is a potential that many aged and small coal units may be impacted by environmental regulations. A reduction in units on the system could present potential operational concerns.

Additional Information

Recent environmental regulation rule proposals from the EPA and the uncertainty around carbon control continue to provide uncertainty and impacts to configuration and operation of the bulk power system. The impacts of the rules may result in retirements of generation within the MISO footprint. If this occurs, the system within MISO may see reliability impacts from the generation and transmission perspectives.

To maintain compliance with environmental rules, capacity will be reduced from the system associated with both retrofits and retirements. In the MISO footprint, this will reduce the amount of existing capacity available to meet resource adequacy requirements. Transmission adequacy could also be impacted depending on what units retire from the bulk power system as a result of the rules. For example, a unit needed for transmission reliability and voltage support in a metro area may require additional transmission support to meet the reliability requirements on the system.

It is expected that the current proposed rules will impact the coal-fired generation fleet located throughout the MISO footprint. From internal rule evaluation, it is expected that the units most likely targeted for retirement will be small, old units. However, all units that do not meet the proposed rule requirements will be impacted through retrofit costs and operational impacts of the new equipment. Carbon reduction requirements could put additional pressure on the coal fleet in the MISO footprint and result in additional retirements. In fact, the uncertainty around future carbon reduction requirements may result in units to retire rather than retrofit to reduce future cost risks.

Up to this point, the proposed EPA rules and the uncertainty around carbon reduction has not resulted in any current reliability issues. MISO is evaluating the potential impacts of the rules to be prepared to meet the stakeholders' needs as they determine whether units are to retire or retrofit. This will include evaluating impacts on resource and transmission adequacy. It is expected that a proposed new capacity construct within MISO will also provide additional mitigation of reduced capacity on the system by allowing better management and integration of demand side resources and the management of the participation of intermittent resources.

Assessment Area Description

MISO, a Planning Authority, operates as a single Balancing Authority and experiences its annual peak during the summer season. MISO's scope of operations covers 750,000 square miles, which includes 13 states. MISO's Midwest Energy and Operating Reserves market includes 347 market participants, which serve over 40 million people.

MRO-Manitoba Hydro

Introduction

Manitoba Hydro is a Provincial Crown Corporation providing electricity to 521,600 customers throughout Manitoba and natural gas service to 261,150 customers in various communities throughout southern Manitoba. Manitoba Hydro also has formal electricity export sale agreements with more than 35 electric utilities and marketers in the Midwestern U.S., Ontario, and Saskatchewan.

Manitoba Hydro is the single Planning Authority and Balancing Authority and is a coordinating member of the Midwest Reliability Organization. The MISO is the Reliability Coordinator for Manitoba Hydro.

Manitoba Hydro collects various data including: historical operating data, neighboring utility data, physical equipment data, forecasting data (generated from internal and external computer models that integrate various data sources), and internal and external reports. Analysis methods include industry accepted practices using computer models.

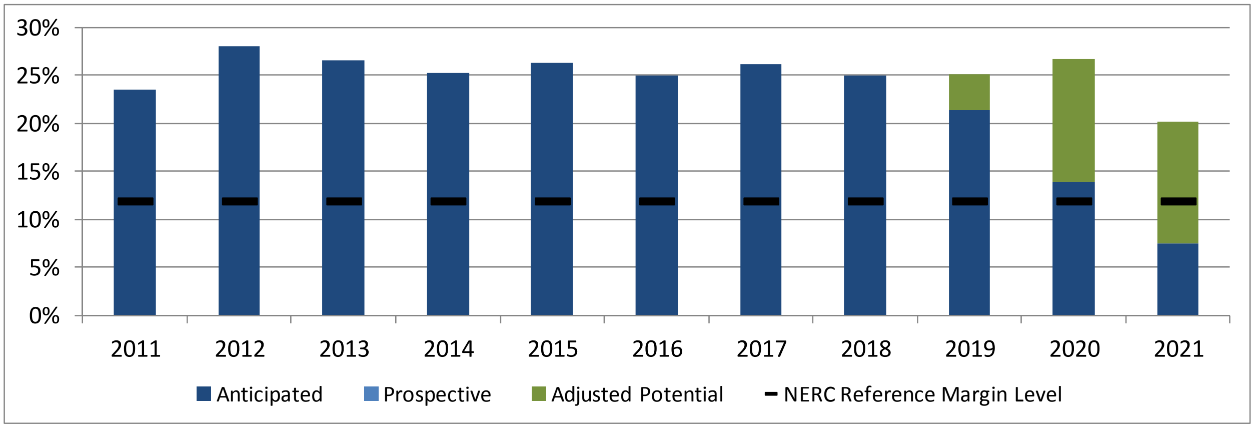
Reliability Assessment

The Manitoba Hydro Power Supply business unit is tasked with preparing the resource assessment portions, while the transmission business unit is tasked with preparing the transmission assessment portion. Manitoba Hydro participates in the reliability assessment and planning studies performed annually by the Mid-Continent Area Power Pool (MAPP) Planning Authority. The MAPP System Performance Assessment is designed to develop an understanding of the transmission system topology, behavior and operations, as well as to determine existing and planned facility improvements.[204] This study will assess the reliability of the MAPP region for the current, near-term, (1-5 year) and long-term (6-10-year) transmission expansion plans. In an effort to identify reliability issues in the MAPP Region, which comprises MAPP-US and MAPP-Canada, this assessment will discuss the transmission system assessment by means of thermal, voltage and dynamic stability analysis for the system above the 100-kV voltage level including tie lines under both pre-contingency and post-contingency system conditions. Contingencies for NERC Category B, Category C and a number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entities,\, will be selected for evaluation. Depending on the results of the assessment study, further studies on more specific alternatives to improve system performance may follow.

The Anticipated Resources Reserve Margin is projected to range between 7.5 and 28.1 percent during the winter seasons of 2011-2021. The Adjusted Potential Reserve Margin remains above the NERC Reference Reserve Margin Level of 12 percent throughout the assessment timeframe (Figure 82).

[204] Appendix A of the MAPP 2010 Regional Plan - 2011 to 2021 meets the MAPP Members Reliability Criteria, NERC and/or the MRO Transmission Planning Standards TPL-001-0 thru TPL-004-0.

Figure 82: Annual On-Peak Planning Reserve Margins



As a predominantly hydro region, Manitoba has both an energy criterion and a capacity Reserve Margin criterion. These criteria are set forth based on system historical adequacy performance analysis with reference to probabilistic resource adequacy studies. The energy criteria requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions (on the 96-year hydraulic flow record) are repeated. The capacity Reserve Margin criterion requires at least 12 percent reserves above the forecast peak demand throughout the long-term assessment period. Manitoba Hydro performs its own Loss-of-Load Expectation (LOLE) studies and in previous years, also participated in MAPP Regional LOLE studies.[205]

During the summer, all resources required to meet forecasted load are internal to Manitoba Hydro. During the winter, Manitoba Hydro has the ability to import between 350 and 500 MW of capacity available for serving forecasted load.

The Manitoba Hydro system is interconnected to the MISO system in United States and two other Canadian electric power systems.[206] In resource adequacy assessment, Manitoba Hydro considers existing Firm contracts and potential interconnection reserve, sharing only with the United States, (MISO West Region) but not with neighboring Canadian utilities. The potential interconnection reserve sharing between US and Manitoba systems is assumed to be possible only if the MISO West system is resource adequate. There is no difference in treatment between the short-term (1-5 year) and long-term (6-10-year) Reserve Margin requirements. Manitoba Hydro does not include behind-the-meter generation in this reliability assessment.

Natural gas-fired generation represents only about 10 percent of Manitoba Hydro's generation resource capacity. The peaking combustion turbines have local fuel oil storage for short-term supply interruptions. Forced outages are considered in the resource adequacy studies and sensitivity analysis

[205] The MAPP LOLE study for the 10-year planning horizon (2010-2019) dated December 30, 2009 included Manitoba in the study region. Manitoba Hydro is in the process of preparing a 2011 LOLE study, developed using the Multi-Area Reliability Simulation (MARS) program, developed by the General Electric Company (GE).

[206] The Saskatchewan Power Corporation (SaskPower) and Ontario's Independent Electricity System Operator (IESO)

on the low forced outage rates of the hydro units (the primary generation in Manitoba Hydro's system) indicates minimal impact on planning Reserve Margin requirements.

Manitoba Hydro considers extended drought conditions in long-term resource planning and adequacy, implementing specific energy criterion for extended drought conditions. The criterion requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions on the hydraulic flow record are repeated. In addition, hydro units are modeled as energy limited resources in the resource adequacy study, with the energy limits for the applicable cases based on drought conditions.

Wind resources represent about 4 percent of the nameplate capacity of generation resources within Manitoba. For the 2011 resource adequacy study, wind generation was modeled as a simple load modifier with an 8 percent capacity value, except during the winter season[207] when the capacity value is zero. Manitoba Hydro also does not have transmission-limited resources. Certain resources external to Manitoba Hydro, which may provide some assistance on a non-Firm basis to Manitoba Hydro such as those resources in MISO region, may be considered as transmission-limited resources. The transmission restriction of these resources is considered using a multi-area approach. In the multi-area approach, a generation system is modeled as a number of interconnected areas. The areas are defined by the limiting interfaces that may exist throughout the transmission system. The interface limitations are determined through comprehensive thermal and/or stability analyses.

Manitoba has no Renewable Portfolio Standard (RPS) and thus there is no impact of such mandates on the resource adequacy process in Manitoba. For the 2011 resource adequacy study, wind was treated as an energy resource with annual output equal to 85 percent of the long-term expected annual wind energy. There are no utility-scale solar resources in Manitoba.

Manitoba Hydro currently has two variable wind generation plants that are operational in Manitoba. A 100 MW plant connected to the 230 kV bus at St. Leon (in-service date of July 2006) and a 138 MW plant (projected in-service date of March 2011) connected to the 230 kV bus at Letellier station. Reliable integration or interconnection has been ensured by continually updating our interconnection requirements based on best practices in the industry.[208]

The wind penetration level is not high enough to noticeably impact reliable operations; however, the approach to forecasting has changed. Rather than rely on a forecast from the Generator Owner, Manitoba Hydro calculates a central forecast. Wind resources represent about 4 percent of the nameplate capacity of generation resources within Manitoba. Manitoba Hydro has conducted wind integration studies at an hourly resolution level, including operation and production simulations and did not find significant technical issues arising at wind penetration levels of up to 20 percent of nameplate

[207] December through February.

[208] Manitoba Hydro transmission system interconnection requirements are posted on the Manitoba Hydro Oasis website: http://oasis.midwestiso.org/documents/mheb/MH_transmission_interconnection_requirements-V2010.pdf.

capacity. The hydro generation within Manitoba provides adequate flexibility to integrate wind at currently expected levels.

Manitoba Hydro has approximately 225 MW of Demand Response under Options A, C, E and R of its Curtailable Rates Program.[209] Due to modeling complexities combined with uncertainty as to the customer's long-term commitments to the Curtailable Rates program, these Demand Response resources were not considered in the pending 2011 resource adequacy study. While this assumption is conservative for now, its appropriateness will be reviewed for future LOLE studies.

At the current time, the only potential unit retirement is of a coal generating unit, scheduled for approximately 2019, which represents less than 2 percent of the nameplate generation capacity within Manitoba. The retirement of this unit will not have a significant impact on reliability due to its small size. New hydro generation is also expected to come into service near the same time as the retirement.

Currently Manitoba Hydro does not have any UVLS relays installed and has no plans to install any in the 10-year planning horizon. A new special protection is planned to be installed at Grand Rapids. When north to south transfers are high, there is potential to thermally overload the Grand Rapids Generating Station outlet lines if one of the lines trips. The SPS will convert one of the generating station units to a synchronous condenser within 5 minutes of an outlet line tripping thus preventing line overload while maintaining dynamic reactive reserves. This will be a permanent solution.

Manitoba Hydro has conducted an assessment of network vulnerabilities, considering low probability extreme weather that could result in catastrophic outages of its HVdc transmission lines located on a common right-of-way corridor. Manitoba Hydro has evaluated the risks of these extreme disturbances and associated consequences and has determined that the consequences are too great to be ignored. To mitigate potentially catastrophic events and improve reliability, a third +/-500kV HVdc bipole transmission line located on a separate corridor and new converter stations are planned with an in-service date of 2017 to provide an alternative transmission route and power injection point in the areas south of Manitoba. Until these facilities are in place, Manitoba Hydro has developed a Hydro Proximity Report application that monitors storm events and proximity of these storms to key infrastructure. If the Hydro Proximity Report indicates that a tornado or other strong wind event is threatening key infrastructure, Manitoba Hydro will reduce transfers to ensure that the event will not interrupt its interconnection to the U.S.

A reliability assessment study is performed annually by the MAPP Transmission Reliability Assessment Working Group (TRAWG). NERC Category A (system intact), NERC Category B, and selective NERC Category C and known multiple element single contingency outages (*i.e.,* common tower) are performed according to NERC criteria. A number of NERC Category D contingencies were also evaluated. Assessments are carried-out on model years 2011, 2016 and 2021 for winter peak, summer peak and summer off-peak, high transfer conditions. Dynamic analysis was completed on 2011, 2016 and 2021

[209] Manitoba Hydro Curtailable Rate Program for Individual Customer Loads.

for winter peak and summer off-peak high transfer models. The transmission system is expected to perform reliably throughout the analysis period.

Manitoba Hydro performs ongoing system planning studies ranging over the 10-year planning horizon to assess and enhance reliability, integrate new generation, address forecast load growth connect new large industrial load and facilitate transmission service requests. Generator interconnection studies and studies for long-term transmission service are posted on the Manitoba Hydro OASIS website.[210] Any reliability issues are addressed by appropriate facility additions to ensure compliance with the NERC TPL standards over the 10-year planning horizon. Manitoba Hydro publishes a 10-year Plan annually which is posted on this website.

There is a dynamic reactive power limited area near the town of Thompson in northern Manitoba. Transient voltages following fault clearing can be low enough to cause induction motor tripping at a nearby customer. A 165 MVAr static reactive compensator is being added in 2011 to provide post-disturbance transient voltage support. The support will be needed when the Wuskwatim generating station comes into service during spring 2012). Reactive power support (three 73.4 MVAr cap banks) is being added at Riel in 2014 to ensure the maintenance of a sufficient, pre-contingency reactive Reserve Margin on the Dorsey synchronous condensers. The Grand Rapids generator is becoming "reactive power limited," especially when north to south transfers are high. Nearby shunt line reactors (two 40 MVAr) will be made switchable in 2011 to provide additional reactive power reserve.

Manitoba Hydro does not have a documented voltage stability margin criteria from PV/QV or other analysis for long-term planning because the area is not voltage stability limited for system intact conditions with peak loads and Firm transfers. Manitoba Hydro includes the following documented criteria that serve to mitigate voltage collapse:

- Reactive power margin:
    - Dorsey 300 MVAr capacitive reserve with one 160 MVAr synchronous condenser out of service.
    - 125 MVAr reserve at Grand Rapids Generating Station with all units in-service
    - One generator unit at Seven Sister's Generating Station out of service during high Manitoba – Ontario transfer conditions.
- 0.7 per unit minimum transient post-disturbance voltage
- Pre-contingency voltages must be within normal steady-state limits of approximately 0.95 to 1.05 per unit and post-disturbance steady state voltages must be within 0.9 to 1.10 per unit.

Operation studies require the maintenance of a 5 percent margin in power (as measured from the nose of the power-voltage (PV) curve) when determining maximum operating points.

Manitoba Hydro has experience with FACTS technology on the Bulk Electric System. The 150 MVAr Ponton SVC has been connected to the 230 kV grid in northern Manitoba since April 2006. Manitoba

[210] http://oasis.midwestiso.org/OASIS/MHEB.

Hydro is planning to commission a second SVC in August 2011. The 165 MVAr SVC will be connected to the Birchtree station near Thompson. Manitoba Hydro has several phasor measurement units (PMU) installed and has plans to commission a Wide Area Measurement System (WAMS) with small signal stability tools in 2011. This system will improve the ability to commission and confirm settings of power system stabilizers. During the next 10-years, Manitoba Hydro expects to integrate this system into the control center for real-time visualization and improved state estimator accuracy.

Manitoba Hydro's Transmission Business Unit has started to build a Wide Area Measurement System which will ultimately be used to enhance situational awareness and decision support for the system operator. Manitoba Hydro is currently installing PMUs at a number of locations on Manitoba Hydro system, as well as a data concentrator to manage and archive the collected data. Future steps will include the implementation of on-line stability simulation capabilities, visualization and decision support tools which are currently being developed by the industry. None of the current or future smart grid programs in Manitoba are expected to have potential reliability issues.

Federal environmental regulation, currently under review, could require the retirement of a 95 MW coal-fired generating unit, after 45 years of service. This unit will represent less than 2 percent of the nameplate capacity in Manitoba in 2015 and current plans include keeping the unit online until at least 2019. Early retirement could require the advancement of other planned generation. The resource planning process considers sensitivities that reflect the impact of potential environment regulations and currently there are no potential reliability issues arising from these regulations.

There are no reliability impacts that have been identified for the projects not meeting their expected in-service dates. Where project delays have been encountered, operating guidelines have been developed to mitigate any potential reliability impacts.

Demand

The 2011/2012 winter demand forecast of 4,517 MW increases to 4,992 MW in the winter of 2021/2022, with an average growth of about 43 MW or approximately 0.91 percent per year (Table 65).

Table 65: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	4,517	4,992	475	0.91%	10.5%
Net Internal	4,291	4,766	475	0.96%	11.1%

This forecast includes adjustments in historical load to remove the weather effect for the purpose of forecasting future load. Normal weather for the forecast was based on 25 years of Winnipeg temperatures from April 1985 to March 2010. Economic forecast assumptions are derived from the Economic Outlook and the Energy Price Outlook. These documents contain Manitoba Hydro’s forecasts of economic variables including prices of electricity, natural gas and oil, Gross Domestic Product (GDP), Manitoba population, and housing. The number of homes in Manitoba is forecast to increase an average of 0.9 percent over the forecast period. Gross Domestic Product (GDP) in Manitoba is forecast to be 2.6 percent in 2010-2011, 3.1 percent in 2011-2012, 2.8 percent in 2012-2013 and 1.7 percent in 2013-2014 and beyond.

Manitoba Hydro is a single individual member. Aggregation of different member peak demands is not required. Manitoba Hydro's current and projected Power Smart Energy Efficiency programs include customer service, cost-recovery, and incentive-based programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of energy-efficiency and customer self-generation programs, is designed to help customers conserve energy, reduce energy bills and protect the environment.

The measurement and verification activities conducted by Manitoba Hydro are tailored to the specific requirements of each Energy Efficiency program and/or sector. The intensity of measurement and verification is based upon variability of use and the benefit of measurement in relation to the cost.

- The residential market is characterized by a large volume of customers with typically homogeneous energy use patterns. Due to the size and homogeneity of the sector, measurement and verification is minimal. Energy savings are based upon a deemed savings per technology in conjunction with surveyed use patterns.
- The commercial market is characterized by fewer numbers and customers with typically homogeneous use patterns. Measurement and verification is limited due to cost and/or benefit implications and the ability to use deemed savings and standardized use patterns based up technology.
- The industrial market includes programs which will establish an appropriate measurement and verification plan for each customer. The plan will follow the principles outlined in the International Performance Measurement and Verification Protocol (IPMVP) – Volume 1 (March 2002).

The Evaluations Department within Manitoba Hydro models evaluations according to the International Performance Measurement and Verification Protocols (IPMVP) from the Efficiency Valuation Organization and DSM best practices. Additional information on Energy Efficiency and DSM programs for Manitoba Hydro is shown below (Table 66).

Table 66: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**42**	**156**	**114**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	227	227	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**227**	**227**	**-**
Total Demand-Side Management	**269**	**383**	**114**

Manitoba Hydro's Curtailable Rate Program is not intended to reduce the peak demand but rather to meet reliability obligations. Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves.

Upon a system contingency or emergency, the System Control Centre may curtail the customer by the terms of the contracts agreed upon in the Curtailable Rate Program. The Control Centre measures the amount of curtailment through the EMS and/or SCADA system and verification is monitored throughout the curtailment. The curtailment is logged and a memo is issued after the fact outlining the extent of the curtailment, the amount curtailed, and the reason for curtailment.

Under the Curtailable Rate Program, customers can select various curtailment options which best suits their operation and ability to curtail load on short notice. Manitoba does not currently have a Renewable Portfolio Standard (RPS).

Load forecast variability information is provided in its Electric Load Forecast document.[211] The historical annual variation in weather adjusted load was analyzed to produce an estimate of the standard deviation and correlation coefficient of past load growth. These were then applied to the base 50 percent forecast to give a probability-based estimate of the width of the energy and peak confidence bands. The standard deviation of annual energy or annual peak due to weather is approximately 2 percent of the load, and is independent of the economic-based confidence bands. The document also outlines potential loads - specific situations that if realized may case a significant impact to the Manitoba Hydro forecast.

For the most recent forecast, hourly data was used to develop an improved peak forecast model. The previous peak model used hourly data only at the total system level to determine the system load shape. The new model took into account the load shape of each of the six sectors (Residential All-Electric, Residential Standard, General Service Mass Market, Top Consumers, Distribution Losses and Transmission Losses). Each sector's load growth was applied to determine its future load shape. The load shapes were then combined to form a system load shape to determine the peak.

Generation

Projections for annual on-peak fuel mix as well as annual net capacity change by fuel type are shown below (Figure 83 and Figure 84)

[211] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_62.pdf.

Figure 83: On-Peak Capacity Mix by Fuel Type

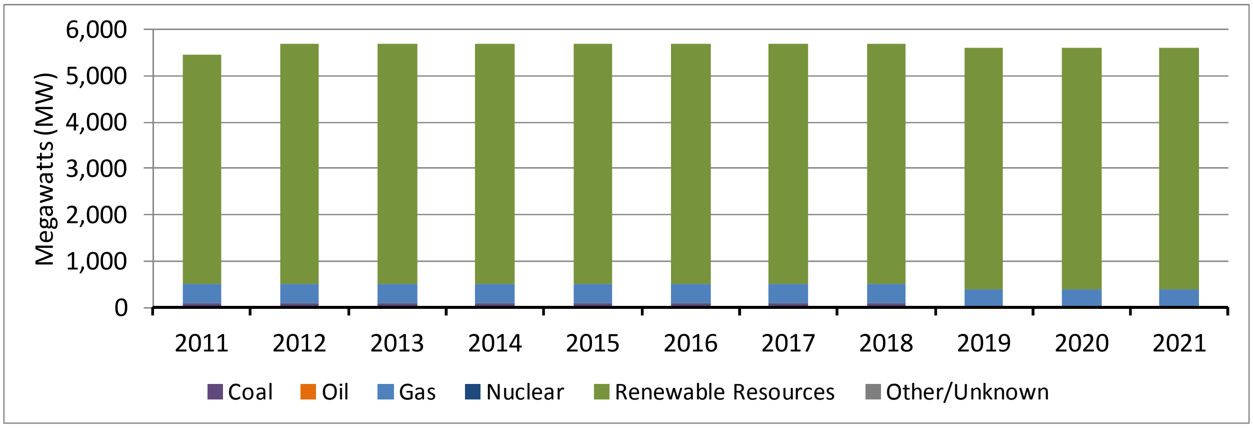
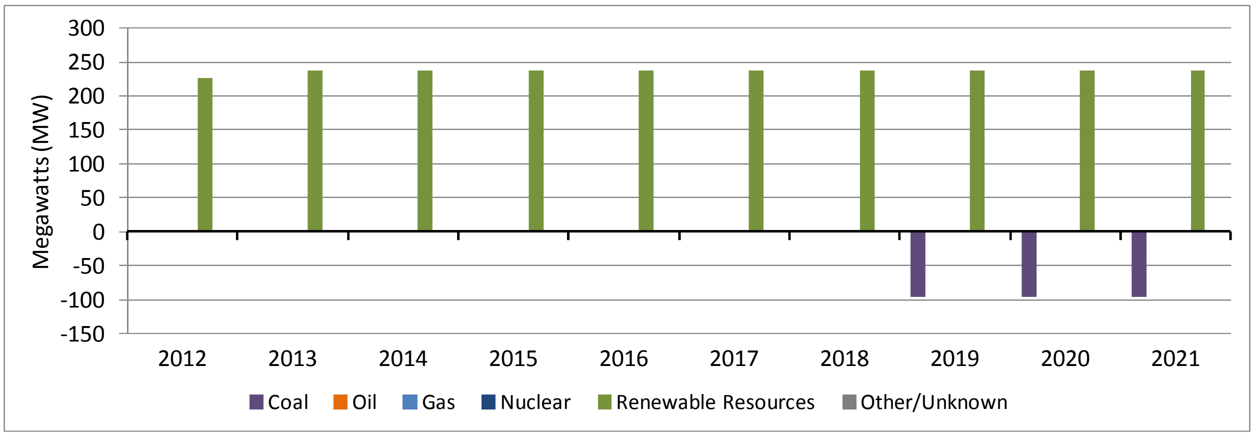


Figure 84: Annual Net Capacity Change by Fuel Type



Existing Capacity resources range between 5,880 MW in the summer and 5,919 MW in the winter. *Existing-Certain* capacity ranges between 5,431 MW in the summer and 5,451 MW in the winter. *Future-Planned* hydro generation includes an additional 33 MW from Kelsey Generating Station upgrade and 204 MW from the construction of the Wuskwatim Generating Station. In 2019 it is expected to retire the coal unit, approximately 95 MW, at the Brandon Generating Station.

Included in the *Existing-Certain* capacity above is the Jenpeg Generation Station, with associated nameplate of 131 MW. The expected on-peak amounts for Jenpeg Generating Station range from 97 MW to 103 MW during the assessment period. This hydro station is considered as variable generation because it is run-of-the-river and considered an energy resource and because its output can only be modified for a 24 hour period. These on-peak capacity values are calculated based on the MRO Generator Testing Guidelines.[212]

Manitoba Hydro has two other existing variable capacity resources, St. Leon wind farm, which has about 104 MW of nameplate capacity and St. Joseph wind farm with a nameplate capacity of 138 MW.

[212] http://www.midwestreliability.org/REL_asr.html.

The on-peak capacity value of wind was assumed to be zero capacity in the winter and 8 percent of nameplate capacity for summer. This is based on a 2009 analysis by MISO for the wind capacity credit for planning year 2010/11. Manitoba Hydro has no *Existing-Certain* or *Future-Planned* biomass sourced capacity (Table 67).

Table 67: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	-	-	-
	Derated	242	242	-
	Wind - Total Nameplate Capacity	**242**	**242**	**-**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	4,959	5,196	237
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**4,959**	**5,196**	**237**
Biomass	Expected	-	-	-
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**-**	**-**	**-**

Manitoba Hydro's reliability assessment includes 630 MW of *Conceptual* capacity resources in 2019-2020 from the construction of the Keeyask Generating Station. Manitoba Hydro has no *Conceptual* variable and biomass sourced capacity.

Manitoba Hydro uses an integrated resource planning process and the need for new capacity requirements of the system are estimated including a 12 percent planning Reserve Margin requirement to meet forecast peak loads and Firm capacity exports, including any seasonal derates. Manitoba Hydro also uses an integrated resource planning process to develop its own resources or purchases the output of a resource such as a wind generation under long-term contract. Thus it has significant control and/or a high degree of confidence of the development of *Conceptual* resources. In addition, the process also allows the identification and categorization of *Conceptual* resources detailed in the long-term power resource plan. Manitoba Hydro does not include any behind the meter generation as part of its capacity resource.

Capacity Transactions

Manitoba Hydro has Firm winter peak capacity imports ranging from 350 MW to 500 MW during the assessment period. Manitoba Hydro does not currently have any Expected or Provisional peak capacity imports during the assessment timeframe. All of Manitoba Hydro's Firm capacity imports are backed by contracts for Firm generation. Imports are backed by Firm transmission up to winter 2014-2015. Contracts after 2014-2015 have roll over rights for the Firm transmission; however the rollover rights have not been exercised as of March 28, 2011.

Short-term planning studies to determine transfer capabilities with neighboring utilities are also conducted:

- Manitoba Hydro – United States (MH-USA) interconnecting tie line transfer limits are developed through joint studies with the Interconnected Study Working Group (ISG) subject to review by the Northern MAPP Operating Review Working Group (NMORWG).
- Manitoba Hydro – Ontario (MH-Hydro One) interface transfer capability is determined from separate analyses conducted by Manitoba Hydro's System Performance department and by Ontario Independent Electricity System Operator (IESO) and is also coordinated with the latest analysis and guides from the Manitoba-Ontario-Minnesota (MOM) interconnection working group.
- Manitoba Hydro – SaskPower (MH-SP) interconnecting tie line transfer limits are developed through joint studies by the two utilities on a semi-annual (winter and summer season) basis. Analyses are conducted to determine interface transfer capabilities for the most probable operating configurations and also examine sensitivities of the transfer capabilities to variances in major network parameters on both sides of the interface.
- Seasonal transfer capabilities are posted prior to the start of the season.[213] The summer season starts May 1, 2011.

The forecasted Firm and expected summer on-peak transfers for Manitoba Hydro is 1,110 MW for 2011 and is estimated to decrease to 725 MW by 2021. The forecasted Firm and expected winter on-peak transfers from Manitoba Hydro are 580 MW for 2011 and estimated to decrease to 325 MW through 2021 (Table 68). Manitoba Hydro's Expected summer and winter peak capacity exports are 250 MW in 2020 and 475 MW in 2021. All Manitoba Hydro's export contracts are backed by Firm generation. Firm export capacity contracts up to April 2015 have Firm transmission service. Beyond this date Firm export contracts have Firm transmission service in MISO.

Table 68: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	-	-	500	350
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**-**	**-**	**500**	**350**
Exports	Firm	1,110	725	580	325
	Expected	-	475	-	475
	Provisional	-	-	-	-
	Total	**1,110**	**1,200**	**580**	**800**
	Net Transactions	**(1,110)**	**(1,200)**	**(80)**	**(450)**

Transmission

Major projects expected to be completed in Manitoba subregion in the planning horizon from 2011 through 2021 are listed as follows:

- St Joseph Wind–Letellier 230 kV line (2011, Under Construction)

[213] http://oasis.midwestiso.org/documents/mheb/ops_guide.html.

- Wuskwatim S.S.–Herblet Lake 230 kV line 1 (2011, Under Construction)
- Wuskwatim S.S.–Herblet Lake 230 kV line 2 (2011, Under Construction)
- Wuskwatim G.S.–Wuskwatim S.S. 230 kV line 1 (2011, Planned)
- Wuskwatim G.S.–Wuskwatim S.S. 230 kV line 2 (2011, Planned)
- Wuskwatim G.S.–Wuskwatim S.S. 230 kV line 3 (2011, Planned)
- Herblet Lake–Rall's Island 230 kV line (2011, Under Construction)
- D54C Tap–Neepawa 230/66 station 230 kV line (2012, Planned)
- R32V Tap–Transcona 230 kV line (2013, Planned)
- R33V Tap–Transcona 230 kV line (2013, Planned)
- Henday–Conawapa Construction Power 230 kV line (2013, Planned)
- Dorsey–Riel 500 kV line (2014, Planned)
- Dorsey–Portage 230 kV line (2014, Planned)
- LaVerendrye–St Vital 230 kV line (2015, Planned)
- St Vital–Letellier 230 kV line (2015, Planned)
- Keewatinoow –Riel 500 kV DC line (2017, Planned)
- Keewatinoow –Henday 230 kV line 1 (2017, Planned)
- Keewatinoow –Henday 230 kV line 2 (2017, Planned)
- Keewatinoow –Henday 230 kV line 3 (2017, Planned)
- Keewatinoow –Long Spruce 230 kV line (2017, Planned)
- Dorsey–Maple River 500 kV line (2018, *Conceptual*)
- Dorsey–Riel 500 kV line (2019, *Conceptual*)
- St Vital - Steinbach 230 kV line (2020, *Conceptual*)

Manitoba Hydro has identified one key project that is required to maintain or enhance reliability. The sectionalization of the existing Dorsey–Forbes 500 kV line and the establishment of the new Riel 500 – 230 kV Substation being built on the east side of Winnipeg. The project will improve the reliability by adding an alternative terminal point for the 500 kV line from the US, thereby preserving existing import capability in case of a major outage at the Dorsey 500 kV substation.

The Keewatinoow–Riel 500 kV DC line is a major new north-south DC line. The new line provides additional transmission capability to address outages of the existing Bipole I or II corridor due to low probability events such as wind bursts, tornados and ice storms. The new DC line also covers for major station outages in the south at Dorsey or in the north at Henday and Radisson.

- There are no major concerns for these projects not meeting their expected in-service dates because these projects are planned to address very low probability events. The consequence of delays is continued exposure to the risk of consequences should such NERC category D events occur.

The D54C Tap to Neepawa 230/66 Substation 230 kV line project was delayed due to resource limitations which delayed the design completion.The deferral of the D54C Tap to Neepawa 230/66 Substation 230 kV line project combined with the proposed new pipeline load increases the risk of undervoltage conditions in this area. As a temporary measure, operational procedures will be implemented to maintain reliability in this area. Additionally, the Brandon Generating Station unit 5 was modified to allow operating as synchronous condenser, which will provide additional reactive voltage support. There are no other transmission constraints that would significantly impact reliability in Manitoba or between Manitoba and its neighboring utilities.

Other significant substation equipment anticipated to be in service in MRO Region in the 2011 through 2021 planning horizon are as follows:

- Grand Rapids Circuit Switchers - G8P & G9F line 40 MVAr reactors
- Thompson Birchtree 95/-50 MVAr (165 MVAr 10-second rating) Static var Compensator
- Wuskwatim-Herblet Lk 230 kV-20 MVAr line reactor
- The Pas 230 kV-20 MVAr line reactor
- Brandon Generating Station 54 MVAr 115 kV Cap (4th)
- Riel 230 kV 3 X 73.4 MVAr capacitors
- Keewatinoow and Riel – 2,000 MW converters at each station
- Riel synchronous condensers (4 X 250 MVAr)
- Dorsey 150 MVAr line reactor
- Dorsey Bank 51, second stage 73.4 MVAr tertiary capacitors
- Riel 2nd 230/500 kV transformer Bank with 2 x 73.4 MVAr tertiary capacitors

Operational Issues

There are no known outages that will impact reliability at this time from a system planning perspective. Operating studies are performed for scheduled transmission or generation outages as required. When necessary, temporary operating guides are developed for managing the scheduled outages to ensure transmission reliability.

Extreme weather conditions may take out key infrastructure and therefore impact reliability. As such, Manitoba Hydro has developed applications that overlay weather conditions with key infrastructure maps. These applications include:

- Ice Vision - for detecting ice build up on transmission lines
- Severe Weather Monitoring – for tracking and measuring storm intensity and its proximity to key infrastructure
- Hydro Proximity Report – for tracking the proximity of forest fires to key infrastructure

Manitoba Hydro uses a 12 percent planning Reserve Margin and plans energy assuming the worst drought on record. Therefore, in most operating horizons, capacity and energy conditions are better than the long-term planning horizon, resulting in spare energy and capacity. If peak demands are higher than expected, Manitoba Hydro can make up the difference through its own resources, imports or the most economic combination of both.

Manitoba Hydro has emergency operating procedures to address capacity or energy emergencies. These procedures include a number of measures to avoid curtailment of Firm load while protecting operating reserves. Example measures include exercising curtailable load, removal of non-essential station service load, activation of contingency reserve sharing group reserves, and assistance from neighboring Balancing Authorities via coordination agreements. There are no new environmental or regulatory restrictions that could impact reliability.

The proliferation of variable resources like wind in adjacent subregions to Manitoba has introduced complexity in the operating horizon. Many wind farms do not build facilities to allow Firm transmission of their wind energy. Loop flow and congestion caused by wind resources outside our service area are the operational issues that arise from integration of these resources. As such, operating guides that curtail wind resources and/or other resources are used as a mitigating strategy to ensure reliable operations when transmission capacity is exceeded. There are no operational changes or concerns resulting from distributed resource integration.

Manitoba Hydro has very little Demand Response; consequently, having no associated reliability concerns. Manitoba Hydro has taken a proactive approach to minimize the occurrences of protection misoperations on the power system. This approach involves two distinct processes. The first process is geared towards designing, selecting, simulating, setting, testing and commissioning protective relays to meet and in many cases to exceed industry, NERC and regional reliability standards. There is regular communication between internal and external stakeholder groups involved in this process. Prior to commissioning, protective relays undergo rigorous tests to verify functionality as well as satellite end to end tests to verify performance. Entities wishing to connect to the Manitoba Hydro system are also subject to these requirements.

In the second process, when a relay protection misoperation occur, a comprehensive review and follow-up by a working group with representation from all stakeholder departments which include System Control, Station Design, System Performance, Transmission Services, Communications and Protection Maintenance. This group meets on a monthly basis with the option of quickly convening should an event require this. The working group uses field information, post fault analysis of recorder and relay information as well as system control topology and flow information to conduct a comprehensive review and follow-up to get to the root cause of why the misoperation occurred and to put corrective measures in place to prevent future occurrences. Should the event involve a connection with a neighboring entity, conference calls and face to face meetings are usually set up to analyze the problem and propose solutions.

Emerging and Standing Reliability Issues

Preparedness for High-Impact, Low-Probability Events

Timeframe

- Current.

Emerging or Standing Issue

- Standing.

Changes to Reference Case

- The reference case includes plans to address the reliability issue: Addition of Riel station (2014) and addition of Keewatinoow to Riel DC line (2017).

Projected Long-Term Impacts

- None.

Regional Reliability Impacts

- A severe event such as by a naturally occurring hazard (*e.g.,* ice storm) could severely limit the north to south transfer capability in Manitoba, which could result in long duration rotating blackouts in Manitoba.

Resource Adequacy Concerns

- Significant loss of transmission due to a corridor loss or station loss can bottle large amounts generation and affect the ability to serve load.

Transmission Adequacy Concerns

- This issue directly affects transmission adequacy. Generation to load transfer capability would be severely diminished for a duration that depends on the underlying cause.

Operational Impacts

- None.

Additional Information

Severe events, such as loss of an entire substation or transmission corridor are low in probability but can have major consequences, such as long-duration rotating blackouts. An assessment of the vulnerability of Manitoba's HVdc facilities to extreme weather and other disturbances was conducted and it was determined the risk was too great to be ignored. To date, Manitoba Hydro has not experienced any reliability issues associated with high impact, low probability events. To mitigate these potential reliability concerns, plans are in place to construct a third north-south 500 kV HVdc transmission line on a separate corridor with new terminal stations by 2017. Until these facilities are in place, severe weather is monitored in the operating horizon. Transfer limits on the HVdc facilities are reduced if the severe weather is threatening key infrastructure. Loss of these facilities at reduced loading will prevent cascade tripping.

Geomagnetic Disturbances

Timeframe

- Short-term.

Emerging or Standing Issue

- Standing.

Changes to Reference Case

- The reference case does not include any specific plans to address the issue.

Projected Long-Term Impacts

- None.

Regional Reliability Impacts

- A severe geomagnetic disturbance is forecast to occur roughly coincident with the peak of sunspot activity that occurs every 12-13 years. The last peak in sunspot activity occurred between 2000 and 2003. The next peak is forecast between 2013 and 2016. The geomagnetic disturbance causes dc current to flow in neutral grounded transformers, which can saturate the banks and lead to shortages of reactive power. Manitoba Hydro analysis conducted to date has indicated that geomagnetic disturbance could impact parts of Manitoba Hydro's 230 kV northern network. The potential impact has not been quantified.

Resource Adequacy Considerations

- None.

Transmission Adequacy Considerations

- The dc current caused by geomagnetic disturbances can cause transformer equipment damage or misoperation of Static Var Compensators. Manitoba Hydro has special equipment specifications and test procedures to minimize this possibility. Monitoring equipment is in place at the forecast worst location (Grand Rapids) to quantify the magnitude of dc current to help warn the operators. Research is being supported to help develop better analysis tools to determine whether further mitigation is warranted or new operating procedures required.

Resource Development Issues

- None.

Operational Impacts

- Manitoba Hydro has developed operating procedures to minimize the impact of a geomagnetic disturbance. These procedures are implemented once the MISO notifies Manitoba Hydro that an upcoming event has met or exceeded thresholds (per Geomagnetic Disturbance Procedure RTO-OP-053-r4). The MISO receives indices from Boulder Colorado that would indicate the intensity of the geomagnetic disturbance.

Additional Information

Geomagnetic disturbances are forecast to occur roughly every 12 to 13 years coincident with the peak in sunspot activity. The next peak will occur in the short-term (2 to 5 year time frame). Geomagnetic disturbances lead to dc current in neutral-grounded transformers, which can saturate the banks and lead to equipment damage and shortages of reactive power. Severe shortages could cause voltage collapse such as the March 13, 1989 collapse of the Hydro Québec system. Geomagnetic disturbances tend to be the most severe and most frequent in northern latitudes. Since the 1989 event, Manitoba Hydro has been monitoring dc current at key locations in Manitoba, new transformers have been specified to withstand dc current without damage and Static Var Compensator (SVC) controls have been tested to ensure that they are stable and immune to the effects of voltage distortion. Geomagnetic disturbance warnings are issued by MISO, which enables the operators to have additional reactive power reserves made ready. To date, these measures have been sufficient to ensure adequate reliability against geomagnetic disturbances. Manitoba Hydro is actively supporting research to develop better monitoring and analysis tools.

Integration of Renewable Resources in Neighboring Regions – Wind

Timeframe

- Long-term.

Emerging or Standing Issue

- Standing.

Changes to Reference Case

- The reference case does not include any specific plans to address the issue.

Projected Long-Term Impacts

- Interconnection of additional variable generation in neighboring regions to Manitoba.

Regional Reliability Impacts

- Long-term planning studies indicate potentially significant loop flow in Manitoba due to U.S. connected wind generation. The loop flow could cause thermal overloads or reduced reactive power reserves in southern Manitoba. In addition, Area Control Error could increase due to lack of fast acting regulating reserves in neighboring regions.

Resource Adequacy Considerations

- None.

Transmission Adequacy Considerations

- In most studies, transmission is being added to only address Firm capacity levels of variable generation (eg. 10 to 40 percent of nameplate capacity), which means a significant proportion of the output is nonFirm. Redispatch may or may not be available in the planning horizon to address transmission adequacy issues. It is difficult for third party systems to predict the potential impacts of future variable generation.

Resource Development Issues

- None.

Operational Impacts

- The proliferation of variable resources, like wind, has introduced complexity into the operating environment. Many wind plants do not build facilities to allow Firm transmission of their wind energy. Loop flow and congestion caused by wind resources outside Manitoba Hydro service area are the operational issues that arise from integration of these resources. As such, operating guides that curtail wind resources and/or other resources are used as a mitigating strategy to ensure reliable operations when transmission capacity is exceeded.

Additional Information

Neighboring regions to Manitoba have aggressive renewable energy mandates (*e.g.,* 10 percent of demand energy supplied by renewable in the short-term and up to 25 percent in the long-term) and the majority of new resources are expected to be wind. Wind plants are characterized as having a relatively low capacity factor of 10 to 40 percent and being highly variable. In most studies, transmission is being added to only address the Firm capacity levels of variable generation, which means a significant portion of the wind output is non-Firm. Re-dispatch varies in availability during the long-term timeframe in its ability to address transmission adequacy issues. It is difficult for third party systems to project the potential impacts of future variable generation. Long-term planning studies indicate potentially significant loop flow in Manitoba due to variable generation. The loop flow could cause thermal overloads or reduced reactive power reserves in southern Manitoba. In addition, the area control error could increase due to lack of fast acting regulating reserves in neighboring regions. Operating guides that curtail wind resources and/or other resources are used as a mitigating strategy to ensure reliable operations when transmission capacity is exceeded.

Assessment Area Description

Manitoba Hydro is a provincial Crown Corporation and the sole provider of electricity to 521,600 customers throughout Manitoba. Manitoba Hydro is its own balancing authority. The electricity is transmitted over nearly 62,140 miles of transmission and distribution lines. Manitoba is one of ten Canadian provinces and has an area of 250,950 sq mi. The Assessment Area is winter-peaking.

MRO-MAPP

Introduction

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of the following states and provinces:

- Iowa
- Minnesota
- Montana
- North Dakota
- South Dakota

MAPP sends each member in its Planning Authority an assessment data request to submit its Transmission, Operations Issues, Reliability Assessment and forecasted Demand and Resources sections for the long-term planning horizon. The forecasted Demand and Resources are then aggregated to determine the MAPP regional Demand, Generation, and Reserve Margin forecasts for the assessment timeframe. MAPP also performs an analysis against past performance, resource adequacy study results, and the NERC Transmission Planning (TPL) and Modeling, Data and Analysis (MOD) Standards.[214]

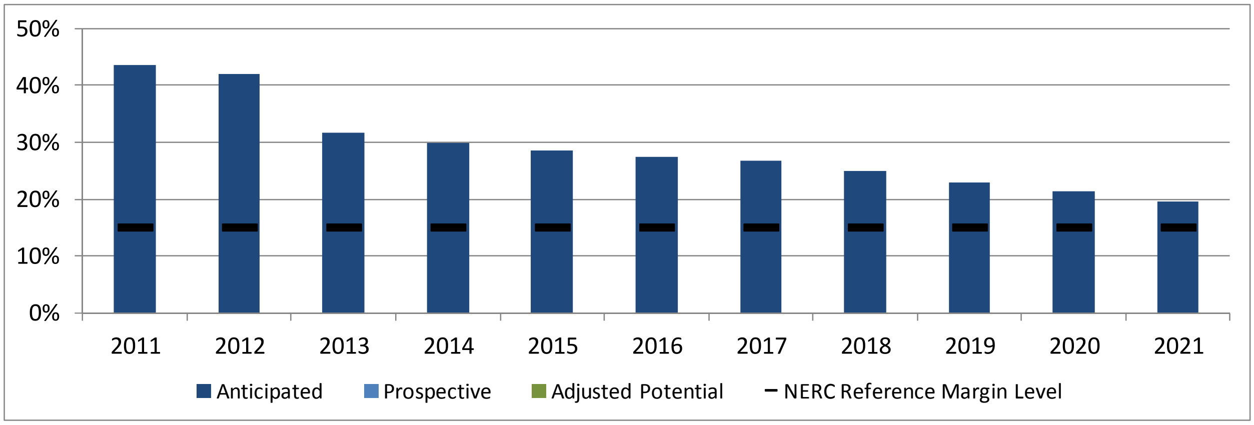
The 2011 MAPP LTRA assesses the reliability of the MAPP footprint through each of the MAPP Members.

Reliability Assessment

Some members of MAPP self impose a planning Reserve Margin as identified in the Loss-Of-Load Expectation (LOLE) study performed and completed by MAPP on December 30, 2009. The MAPP LOLE study requires a 15 percent Reserve Margin for predominantly thermal systems, and 10 percent Reserve Margin for predominantly hydro systems. This minimum Reserve Margin requirement is applied throughout the long-term assessment period. The projected Anticipated Resources Reserve Margin ranges from 43.5 percent to 19.6 percent between 2011 and 2021 (Figure 85). To meet the target Reserve Margin levels, MAPP relies on internal resources only. For summer 2011, 7,359 MW of *Existing-Certain* capacity resources are relied on to meet the summer 2011 forecasted Total Internal Demand of 4,810 MW. No specific analysis is performed to ensure external resources are available and deliverable. However, to be counted as Firm capacity, the various transmission providers require external purchases to have a Firm contract and Firm transmission service. Distributed generation or behind-the-meter generation is considered as a reduction in load, unless it is explicitly reported.

[214] 2010 MAPP System Performance Assessment; MAPP Members Reliability Criteria and Study Procedures Manual, November, 2009; MAPP Small Signal Stability Analysis Project Report, June 2007; MAPP Loss of Load Expectation Study 2010-2019, December 2009.

Figure 85: Annual On-Peak Planning Reserve Margins



MAPP did not experience any extensive drought or extended forced outages in 2010. Interruptions or other conditions such as extended drought or forced outages are considered in the LOLE studies. MAPP also does not have any energy-only resources or transmission-limited resources that are considered in the resource adequacy assessment.

MAPP currently does not have a Renewable Portfolio Standards (RPS) or any other mandate that impacts its resource adequacy process. MAPP uses a methodology that is based on a median of actual wind output. The four peak hours per day for each and every day of the four summer months are used. This dataset uses 10-years or the life of the wind farm. Planning for wind resources involves appropriate MAPP peer review of the generator interconnection study results and approval by the MAPP Design Review Subcommittee to ensure reliable integration and operation of variable resources. MAPP members use an annual interruption test of their certified interruptible Demand Response customers. The demand must be offline in 10 minutes to be certified. There are no anticipated changes to the planning approaches. MAPP currently does not have any unit retirements that have a significant impact on reliability.

MAPP does not have a regional Under Voltage Load-Shedding (UVLS) program and does not expect any additional UVLS schemes installed in its Planning Authority footprint. Existing schemes are implemented on local distribution systems. MAPP does not plan to install any SPS in lieu of planned bulk power transmission facilities.

MAPP performs a reliability assessment annually. The MAPP System Performance Assessment is an assessment to develop an understanding of the transmission system topology, behavior and operations.[215] In addition, the study is done to determine if existing and planned facility improvements identified in Appendix A of the MAPP Regional Plan[216] meets the MAPP Members Reliability Criteria, NERC Transmission Planning Standards TPL-001 thru TPL-004 or applicable MRO Regional standards. This is an assessment of the reliability of the MAPP Region for the present, near term (years one through

[215] 2010 MAPP System Performance Assessment.

[216] Not publically available.

five) and long-term (years six thru ten) transmission planning. The MAPP reliability assessments include studying extreme events. A voltage stability study is currently underway that will account for any system changes that have occurred since the last study performed in 2005. Through the TPL process, MAPP annually verifies that the planning models include reactive power resources to ensure that adequate reactive resources are available to meet the required system performance throughout the 10-year study period. The Reliability Coordinator for the MAPP Members also performs a voltage stability study in the operating horizon and if any issues are found would be included in the next planning study. There have not been any dynamic or static reactive power-limited areas identified in MAPP. MAPP does not have criteria for voltage stability margin.

MAPP does not have any current plans to deploy new technologies, systems, or tools including smart grid programs. MAPP Members continue to evaluate such options for future reliability improvements. There is an increase in wind turbine installation in light of potential environmental regulations. Many states have mandated utilities achieve an increased percentage of resources from renewable generation sources. MAPP continues to evaluate its overall resource mix and does not foresee any potential reliability issues based on the current and future resource mix.

There are no reliability impacts that have been identified for the projects not meeting their expected in-service dates. Where project delays have been encountered, operating guides have been developed to mitigate any potential reliability impacts.

Demand

MAPP assumes normal weather and normal economic assumptions in the 2011-2021 50/50 demand forecast. Last year's annual growth rate was 1.4 percent, compared with this year's annual growth rate of 2.08 percent in summer for the 2011-2021 assessment timeframe (Table 69). Part of the higher annual growth rate can be attributed to the increasing development in the oil and gas production in the Bakken Formation in western North Dakota and Eastern Montana. In April 2008, the U.S. Geological Survey (USGS) estimated that the Bakken Formation is larger than all other current USGS oil assessments of the lower 48 states and is the largest "continuous" oil accumulation ever assessed by the USGS.[217] Another factor in the increase in load growth is the assumption that the economy in the MAPP assessment reporting area has recovered enough to assume normal economic conditions. Non-coincident internal peak demands were used to aggregate individual Member loads for use in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions.

Table 69: On-Peak Demand

Demand	2011 (MW)	2021 (MW)	Total Growth (MW)	Average Annual Growth (%)	Assessment Period Change (%)
Total Internal	4,810	6,035	1,225	2.08%	25.5%
Net Internal	4,704	5,905	1,201	2.09%	25.5%

[217] http://www.usgs.gov/newsroom/article.asp?ID=1911.

Interruptible Demand and Demand Side Management programs are used by a number of MAPP members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the summer season. Interruptible Demand and Demand Side Management (DSM) programs, amount to approximately 2.2 percent per year of the MAPP Projected Total Internal Peak Demand (Table 70). MAPP Members use various measurement and verification programs for Demand Response, such as those based upon International Performance Measurement and Verification Protocols (IPMVP).[218] MAPP does not currently track Energy Efficiency programs; however, these programs may be reflected in the load forecasts of certain LSEs.

Table 70: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**-**	**-**	**-**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	87	107	20
Contractually Interruptible (Curtailable)	19	23	4
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**106**	**130**	**24**
Total Demand-Side Management	**106**	**130**	**24**

Each MAPP member uses its own forecasting methodology. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. Peak demand uncertainty and variability due to extreme weather and/or other conditions are accounted for within the determination of adequate generation Reserve Margin levels. The latest MAPP LOLE Study report showed an increase in Reserve Margin target of about 2 percent for an extreme winter peak. MAPP Members use a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss of Load Expectation (LOLE) and/or the percentage Reserve Margin necessary to obtain a LOLE of 0.1 day per year or 1 day in 10-years. The load forecast uncertainty considers uncertainties attributable to weather conditions.

Generation

Projections for seasonal peak capacity mix and the net capacity changes from 2011 through 2021 are shown below (Figure 86 and Figure 87).

[218] http://www.evo-world.org/index.php?option=com_content&view=article&id=272&Itemid=504&lang=en.

Figure 86: On-Peak Capacity Mix by Fuel Type

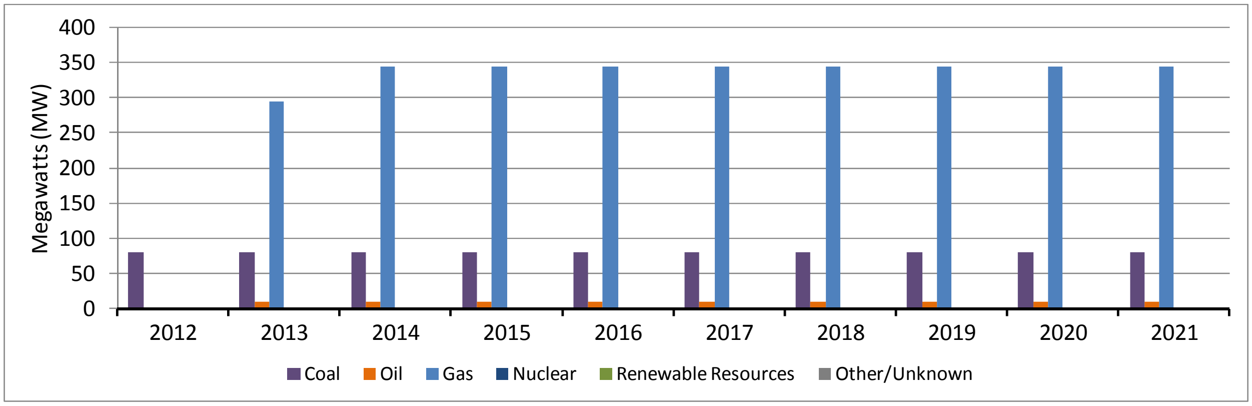
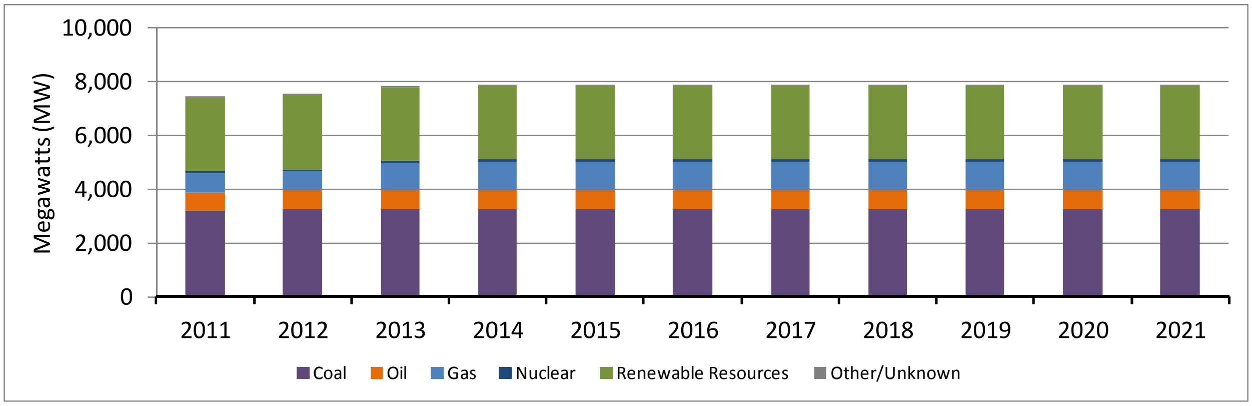


Figure 87: Annual Net Capacity Change by Fuel Type



The *Existing-Certain*, Other and Inoperable capacity resources for the 2011 summer is 8,242 MW. The *Future-Planned* and Other capacity resources that are projected to be in service by end of 2021 are 434 MW. Of the 8,242 MW of Existing capacity resources, 398 MW of variable (*i.e.,* wind and solar) capacity is expected on-peak, with a nameplate rating of 1,166 MW. Of the 8,242 MW of Existing capacity resources, approximately 3 MW of biomass capacity is expected on-peak. MAPP uses a methodology that is based on a median of actual wind output. The four peak hours per day for each and every day of the four summer months are used. This dataset uses 10-years or the life of the wind farm, whichever is shorter. Through the LTRA coordination effort between the MAPP and MISO, Future variable (wind) capacity resources in the MAPP reporting area are reported through the MISO generation interconnection queue process.

There are no *Conceptual* resources projected to be in service during the assessment period. MAPP uses the same methodology above for calculating the expected variable on-peak capacity values. Through the LTRA coordination effort between the MAPP and MISO, *Future-Planned* variable (wind) capacity resources in the MAPP reporting area are reported through the MISO generation interconnection queue process. Current, no additional wind resources are planned within the MRO-MAPP Assessment Area during the assessment period. There are also no *Future-Planned* solar, biomass, or hydro resources expected to come into service through 2021 (Table 71)

Table 71: On-Peak Expected and Derated Renewable Resources

	Renewable Resource	2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	398	398	-
	Derated	768	768	-
	Wind - Total Nameplate Capacity	**1,166**	**1,166**	**-**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	2,346	2,346	-
	Derated	91	91	-
	Hydro - Total Nameplate Capacity	**2,437**	**2,437**	**-**
Biomass	Expected	3	3	-
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**3**	**3**	**-**

Future-Planned and *Conceptual* capacity resources were acquired from each Load Serving Entities (LSEs) within the MAPP Planning Authority Region for use in the reliability analysis or Reserve Margin calculations. A confidence factor of 50 percent was applied across each of the projected assessment year to reduce the *Conceptual* capacity resources amount to a realistic projected value. There are uncertainties involved when using *Conceptual* capacity resources. In-service dates may be deferred or slip and some generation that is projected within the next several years may in fact qualify as "Planned" resources. MAPP also considered when establishing the confidence factor that the LSE's within the MAPP footprint have an obligation to serve and meet their target Reserve Margins. There were no significant increases in distributed generation or behind-the-meter generation in MAPP.

Capacity Transactions

For the 2011, the projected total Firm imports into the MAPP are approximately 352 MW. There are 6 MW of expected capacity imports from other regions in 2011. 200 MW of 352 MW of Firm imports are backed by Firm generation and transmission contracts (Table 72).

Table 72: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	352	205	224	154
	Expected	-	-	6	6
	Provisional	-	-	-	-
	Total	**352**	**205**	**230**	**160**
Exports	Firm	996	911	620	475
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**996**	**911**	**620**	**475**
	Net Transactions	**(644)**	**(706)**	**(390)**	**(315)**

A total Firm export of approximately 996 MW is projected for 2011 to serve loads outside of the MRO Region. 125 MW of 996 MW of Firm exports are backed by Firm generation and transmission contracts.

The net import or export of the MAPP may vary at peak load, depending on system conditions. The total Firm import or export varied minimally through the study period.

Transmission

The following major projects are expected to be completed in MAPP during the 2011-2021 planning horizon:

- Center – Grand Forks 345 kV (Planned – April, 2013)
- Bemidji – Cass Lake 230 kV (Planned – December 2012)
- Cass Lake – Boswell 230 kV (Planned – December 2012)
- Letcher Junction – Mitchell 115 kV (Under Construction – September 2011)
- Big Bend – Lower Brule 230 kV (Planned – December 2014)
- Ames Plant – NE Ankeny 161 kV Line (Planned – June 2012)
- Williston – Tioga 230 kV (In Service – January 2011)
- Brookings – Twin Cities 345 kV (Planned – January 2015)

Northwestern Energy is in the process of building 14 miles of 115 kV line between Western Area Power Administration's Letcher Junction Substation and Mitchell Transmission Substation. This project will provide additional support to the Mitchell area. Basin Electric is planning a new 230 kV transmission line in south central South Dakota. The 70-mile line would run from a new substation near Big Bend Dam to the existing Witten Switching Station near Witten, SD. The new Lower Brule-to-Witten line will help serve member load and enhance reliability and stability of the transmission system in the region. The Williston – Tioga 230 kV project will improve the transmission reliability needed in northwestern North Dakota to meet the increasing load demands and future electric power requirements in northwestern North Dakota.

The City of Ames has limited import capabilities from two existing 69 kV transmission lines. The Ames Plant – NE Ankeny 161 kV project will increase City of Ames import capacity on the transmission system to meet its required demand as well as to offset the loss of generation and prevent a blackout. The project would also increase reliability of the Ames electric system and the regional transmission system.

The Bemidji - Cass Lake - Boswell project will provide increased voltage support not only to the Bemidji and Cass Lake area, but also throughout the Red River Valley and north central Minnesota. The CapX project, Brookings County-Twin Cities transmission line will improve reliability throughout southwest and west central Minnesota and the Twin Cities as well as enable access to new generation, including renewable energy resources in the area. The new line will be constructed from a new substation in Brookings County, South Dakota, to a new substation in Hampton, Minnesota.

There are no reliability concerns in meeting target in-service dates of the transmission projects. Operational procedures to maintain reliability will be implemented if unforeseen delays occur in these or other planned projects. There are no known transmission constraints that can significantly impact reliability. There is no other significant substation equipment expected to be in-service through the assessment period.

Operational Issues

There have been no existing or potential systematic outages identified that could have an impact on reliability for the next 10-years. Operating guides would be put in place to mitigate any reliability concerns, should significant outages occur. If peak demands are higher than expected, MAPP has several options available to maintain reliability, such as importing more resources, using demand-side management programs, or implementing operating guides if reliability concerns develop.

There are no environmental or regulatory restrictions anticipated that would impact reliability over the next 10-years. Restrictions may increase operating costs. No operational changes are anticipated resulting from integration of variable resources and the interconnection of distributed generation on the distribution system. MAPP does not anticipate reliability concerns resulting from high-levels of Demand Response resources. MAPP has about 200 MW of Demand Response resources.

Currently, it is the responsibility of MAPP members to implement steps to reduce the amount of relay protection misoperations. MAPP will continue to monitor the NERC standards related to protection and control. Should the Planning Authority become the responsible entity for these standards; MAPP will work with its members to meet the requirements.

Overall, the MAPP system is expected to operate under all load and Firm exchange levels while meeting the regional reliability criteria. MAPP anticipates normal levels of demand during summer 2011 in the MAPP region.

Emerging and Standing Reliability Issues

Integration of Variable Resources – Planning Perspective

Timeframe

- There is a medium likelihood and consequence of this issue in the short-term and low consequence of this issue in the long-term.

Emerging or Standing Issue

- This is a standing issue currently identified by NERC.

Changes to Reference Case

- This issue will not change the LTRA data.

Projected Long-Term Impacts

- Unknown at this time.

Regional Reliability Impacts

- Some states in the reporting area have mandated an amount of variable resource.

Resource Adequacy Considerations

- This issue has little impact in the MAPP reporting area and has not had much future variable capacity reported.

Transmission Adequacy Considerations

- This issue has no impact on transmission adequacy.

Resource Development Issues

- Current generation interconnection queues might be a barrier.

Operational Impacts

- This issue will have little or no impact on operations.

Additional Information

One of the emerging issues within MAPP is the integration of variable resources, such as wind turbines. Many states in MAPP have a renewable energy mandate or goal. It is expected that the primary source of new renewable energy will come from intermittent resources including wind. The integration of intermittent resources presents new challenges in the region. The integration does not cause undo reliability issues on its own, but does change the nature of how the bulk power system is operated.

As the amount of wind resources increases, their contribution to resource adequacy will also increase. This may introduce additional uncertainty in maintaining system reliability. New wind resources will have an impact on the transmission system and may increase potential for congestion on the system. Intermittent resources also have an impact on the operation of the system generation fleet as resources will need to be dedicated in meeting the potential ramp and minimum generation issues that could occur.

Currently, wind development is focused around meeting the existing state renewable energy mandates. However, if additional regulations are pushed forward (clean energy standards, carbon reduction) more resources may be required. Additionally, economic factors may increase the amount of intermittent resources found on the system such as higher gas prices or lower construction costs for the intermittent resources.

Transmission In-Service Dates

Timeframe

- There is a medium likelihood and consequence of this issue in the short-term. There is a medium likelihood and consequence of this issue in the long-term.

Emerging or Standing Issue

- This is a standing issue currently identified by NERC.

Changes to Reference Case

- This issue could reduce the amount of transmission miles in-service in future years if they do not get built.

Projected Long-Term Impacts

- This issue could impact the amount of TLR used.

Regional Reliability Impacts

- Transmission projects that do not get built will impact reliability through congestion on the existing BES.

Resource Adequacy Considerations

- This issue does not impact resource adequacy as reported through the LTRA. However, an LOLE study may reveal constrained interfaces within MAPP.

Transmission Adequacy Considerations

- This issue may impact transmission adequacy by further congesting the existing BES if new transmission is not built.

Resource Development Issues

- Siting and permitting issues could be barriers to transmission in-service dates.

Operational Impacts

- This issue may constrain the existing BES and affect real-time operations.

Additional Information

Another emerging issue that impacts MAPP, as well as other regions, is the complex process for getting transmission projects built. Transmission projects that do not get built, or get delayed may impact reliability through congestion on the system. This could impact the amount of Transmission Loading Relief (TLR) used. Currently, this issue is not impacting resource adequacy as reported through the LTRA. An LOLE study may reveal constrained interfaces within the MAPP Planning Authority. Siting and permitting issues could be barriers to transmission in-service dates, which may constrain the system and impact real-time operations.

Assessment Area Description

The Mid-Continent Area Power Pool (MAPP) Planning Authority area covers electric utilities operating in all or parts of the following states and provinces: Iowa, Minnesota, Montana, North Dakota, and South Dakota. Currently, the MAPP Planning Authority covers one Balancing Authority and eighteen Load Serving Entities. The MAPP footprint covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. MAPP typically experiences its annual peak demand in summer.

MRO-SaskPower

Introduction

Saskatchewan is a province of Canada and comprises a geographic area of 251,700 sq mi and approximately 1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Authority and Reliability Coordinator for the province of Saskatchewan, and is the principal supplier of electricity in the province. It is a provincial Crown corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

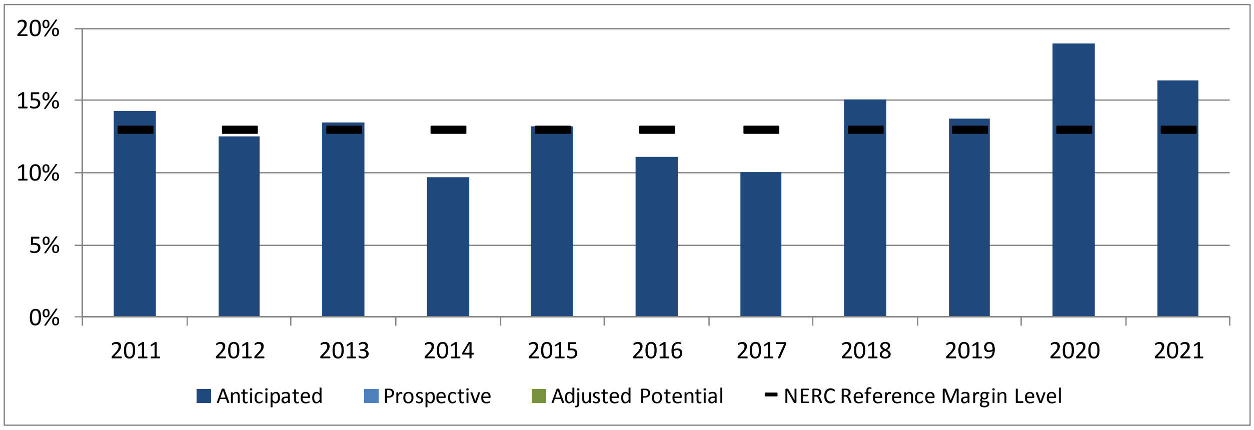
SaskPower owns and operates 7,555 miles of transmission and 52 high voltage switching stations. SaskPower operates networked transmission facilities at the 230 kV and 138 kV voltage levels. This extensive network is designed to serve Saskatchewan's large geographic area and widely-dispersed population. The Saskatchewan transmission system is characterized by relatively long 230 kV and 138 kV transmission lines connecting dispersed generating stations to sparsely distributed load supply points. Saskatchewan has transmission interconnections with the provinces of Alberta and Manitoba, and the US state of North Dakota.

Reliability Assessment

Assessment is performed by SaskPower planning and operating areas.[219] Saskatchewan takes into account factors such as capacity, seasonal derates, forced outage rates, maintenance, intermittent resources and other variables when establishing the Reserve Margin criteria. Saskatchewan uses a probabilistic method of establishing planning reserve or Expected Unserved Energy (EUE)). Saskatchewan performs an annual EUE analysis to determine the requirement for adding new generation resources. Saskatchewan's EUE studies result in a target planning Reserve Margin of approximately 13 percent. For planning purpose, the same target planning Reserve Margin requirement is applied throughout the 10-year assessment period. The Adjusted Potential Resources Reserve Margin for the winter season is projected to range between 9.7 percent and 18.9 percent for the 2011-2021 assessment period (Figure 88). Saskatchewan relies on all internal resources to meet Saskatchewan's capacity margin. Only Firm transactions are used in the assessment. Saskatchewan does not rely on emergency imports, reserve sharing, or external resources other than Firm purchases. The amount of load that is offset by distributed generation or behind-the-meter generation is reflected in the load forecast used for reliability assessment.

[219] SaskPower 2010 Load Forecast Report; SaskPower's NERC LTRA Assessment Data Reporting Form MRO-ERO-2011LTRA Saskatchewan 2010 & 2011 Planning Studies; Manitoba Hydro - Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability.

Figure 88: Annual On-Peak Planning Reserve Margins



Fuel-supply coordination or interruption in Saskatchewan is generally not considered to be an issue due to system design and operating practices.

- Coal resources have Firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Typically there are 20 days of on-site stockpile for each of the coal facilities which in total represent approximately 42 percent of total provincial installed capacity. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves range from 30 to 65 days depending on the plant. Some of the generating units can also switch fuel to natural gas or fuel oil and produce power at a much reduced output if required.
- Natural gas resources have Firm transportation contracts with large natural gas storage facilities located within the province backing those contracts up.
- Hydro facilities and/or reservoirs are fully controlled by Saskatchewan.
- Typically, Saskatchewan does not rely on external generation resources.

Saskatchewan does not anticipate any supply transportation and/or delivery issues. Dynamic and reactive power resources are considered in on-going planning studies. Energy-only and transmission-limited resources are not considered in the resource adequacy assessment for reliability purposes.

Saskatchewan currently does not have a Renewable Portfolio Standards (RPS) or any other mandate that impacts its resource adequacy process. Other than wind, variable resources are not considered in Saskatchewan's resource adequacy assessment. For reliability purposes, Saskatchewan considers 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demands. This is based on using 50 percent of the annual average capacity factor for existing wind facilities during winter period, and 25 percent of the annual average capacity factor during the summer period. The annual average capacity factor for existing wind facilities is around 40 percent of wind nameplate capacity.

Planning approaches developed for variable resources involve appropriate siting for transmission infrastructure and wind energy regimes, and minimizing system impacts due to variability. Variable resources in Saskatchewan are primarily wind. Demand Response is used as required to meet system shortages. Demand Response program are designed to allow customers to curtail load for a set amount of hours and number of curtailments per year. Saskatchewan annually reviews the Demand Response programs to determine if different programs are required.

Saskatchewan has planned unit retirements of approximately 265 MW over the next 10-years that have been included in the reliability assessment. Unit retirements are offset by planned unit additions in Saskatchewan's Supply Plan. Saskatchewan assesses the need for UVLS through on-going planning studies. At this time there are no Firm plans to install UVLS to protect the bulk power system. Saskatchewan has no load targeted by UVLS to protect against bulk power system cascading events. Saskatchewan will install special protection systems to offset planned transmission facilities only where cost effective and technically feasible.

Saskatchewan has emergency preparedness plans as mandated by provincial and Federal requirements to address catastrophic events in general. Saskatchewan does not specifically plan its system for high impact low frequency events, but assessments may be done on as needed basis taking into account the reliability benefit versus cost. In general, the Saskatchewan bulk power system is designed to fail safe for most types of contingencies and to be restored as soon as possible. However, operation of the Saskatchewan system would be performed on a best efforts basis under the types of catastrophic emergency conditions provided as examples. Resources would be offset by planning reserves and external markets as much as possible. If necessary, operational measures include interruptible load contracts, public appeals, and rotating outages.

Earthquakes and hurricanes are historically not a concern for Saskatchewan. Fuel disruptions are minimized as much as possible by system design practices (refer to 2.2.), and Saskatchewan has a diverse energy mix of resources. Coal resources have Firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Natural gas resources have Firm transportation contracts with large natural gas storage facilities located within the province backing those contracts up. Hydro facilities/reservoirs are fully controlled by Saskatchewan, and long-term hydrological conditions are monitored. Geomagnetic induced currents have historically not been a problem for Saskatchewan. Loss of a major import path has not historically been a concern for Saskatchewan, as it typically does not rely on imports to serve load.

Saskatchewan performs ongoing transmission planning and reliability studies to integrate new generation and load and assess reliability. There are also ongoing infrastructure improvements being developed to address any issues identified. Studies consider applicable N-1 and N-2 contingencies, peak and off-peak loading conditions, and Firm and non-Firm transfers in Saskatchewan. Based on the projected load growth primarily in central and eastern Saskatchewan over the next 5 years, several planned transmission reinforcement projects are being added to the Saskatchewan bulk system to maintain adequacy. Approximately 149 miles of 230 kV transmissions, 1,050 MVA of 230-138 kV transformer and 150 MVAr of reactive support are expected to be added. *Conceptual* additions would be approximately 137 miles of 230 kV transmissions and 500 MVA of 230-138 kV transformer capacity.

Approximately 750 MW of planned generation will be added to meet the expected increase in load. Most of this generation is expected to be added close to major load centers, and as a result major transmission reinforcements are also expected to be minimal. There are no known dynamic and static reactive power-limited areas in Saskatchewan. Saskatchewan assesses voltage stability in its planning studies on an as needed basis and uses a guideline of 5 to 10 percent based on load or power transferred. No issues have been identified in operating or planning studies requiring application during peak conditions.

Saskatchewan evaluates new technologies as they become available, and deploys them if it's economical. Saskatchewan does not have any significant smart grid programs that affect the Bulk Electric System. Current efforts are primarily focused on the distribution system. Saskatchewan is monitoring pending Federal and provincial environmental regulations, including all developments in future greenhouse gas emissions regulations. Saskatchewan performs scenario analysis based on potential environmental regulations to determine the effect on generation portfolios. Depending on the outcome of future environmental regulations, Saskatchewan will mitigate any issues related to reliability.

Demand

Saskatchewan develops energy and peak demand forecasts based on a provincial econometric model and forecasted industrial load data. Forecasts take into consideration the Saskatchewan economic forecast, historic energy sales, customer forecasts, normalized weather and historical data, and system losses. Methodology, assumptions and a summary of results are provided in Saskatchewan's annual Load Forecast Report. Weather has a significant impact on the amount of electricity consumed by non-industrial customers. Due to this weather sensitivity, average daily weather conditions for the last thirty years are used to develop the energy forecast. Peak load is forecasted on a heating season basis and represents the highest level of demand placed on the supply system. Last year's 2010-2019 assessment forecasted an average annual increase in demand growth of 2.4 percent. This year's 2011-2021 assessment forecasts an average annual increase in demand of 2.13 percent (Table 73).

Table 73: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	3,407	4,294	887	2.13%	26.0%
Net Internal	3,316	4,203	887	2.18%	26.7%

Coincident hourly peak is used in resource evaluations in Saskatchewan. Saskatchewan has Direct Control interruptible demand contracts with customers. Saskatchewan has established evaluation measures based on standard industry protocols for Demand Response verification. Saskatchewan has Energy Efficiency programs designed to help customers save power, save money and help the environment. These programs include energy-efficiency, Conservation, education, and load management programs. Residential programs focus on consumer education on Energy Efficiency and implementation of energy efficient lighting, appliances and furnace motors including retailer and/or manufacturer partnerships and end-user incentives. Commercial and industrial programs include energy performance contracting, energy audits, and information services along with the implementation of energy efficient lighting, geothermal and Heating, Ventilating, and Air Conditioning (HVAC). Measurement and verification programs are guided by the International Performance Measurement and Verification Protocol (IPMVP) and the California Evaluation Framework.[220] Saskatchewan has Direct Control interruptible demand contracts with customers (Table 74). Saskatchewan has established evaluation measures guided by the International Performance Measurement and Verification Protocol (IPMVP) and the California Evaluation Framework. Saskatchewan currently does not have a Renewable Portfolio Standards (RPS).

Table 74: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	-	-	-
Non-Controllable Demand-Side Management	-	-	-
Direct Control Load Management	91	91	-
Contractually Interruptible (Curtailable)	-	-	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**91**	**91**	-
Total Demand-Side Management	**91**	**91**	-

Saskatchewan develops annual energy and peak demand forecasts based on a provincial econometric model and forecasted industrial load data. The economic forecast provides information on population and household growth, and growth rates for commercial, farm, and oilfield categories. The forecast for the industrial class is based on individual meetings with each customer to record their future load requirements. The provincial econometric model is coordinated with the provincial government to ensure consistency. Summary details are provided in Saskatchewan's annual Load Forecast Report. High and low 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. The probability of the load falling within the bounds created by the high and low forecasts is expected to be 90 percent (confidence interval). Load forecast methodology has not changed due to the economic recession. Load forecast assumptions are routinely adjusted based, in part, on economic conditions and forecasts. In cases where economic performance is expected to decline, the impact would be to lower the actual load forecast due to expected decline in industrial load. Saskatchewan addresses weather uncertainty using a Monte Carlo simulation model that considers a range of weather conditions based on historical observations.

[220] http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf.

Generation

On-peak capacity mix by fuel type as well as the net changes in capacity for the MRO SaskPower Assessment Area through 2021 is shown below (Figure 89 and Figure 90).

Figure 89: On-Peak Capacity Mix by Fuel Type

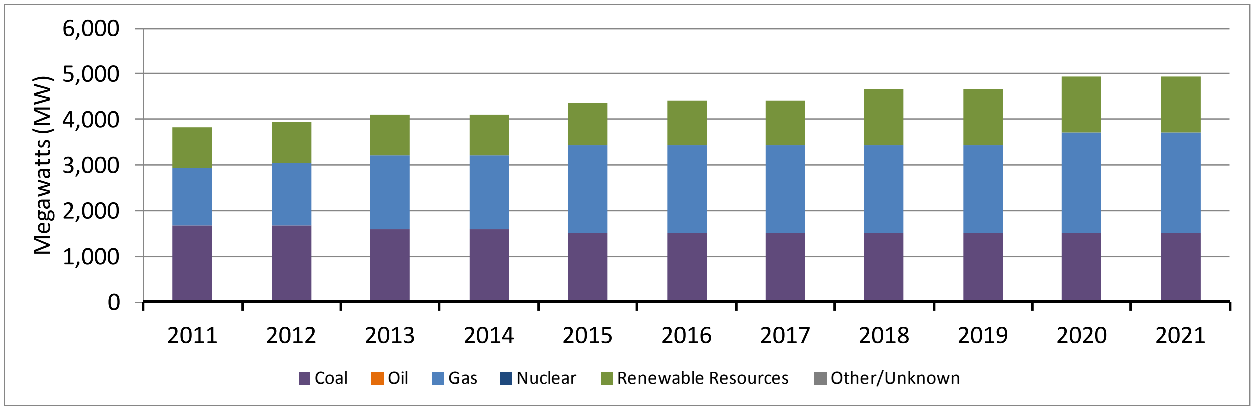
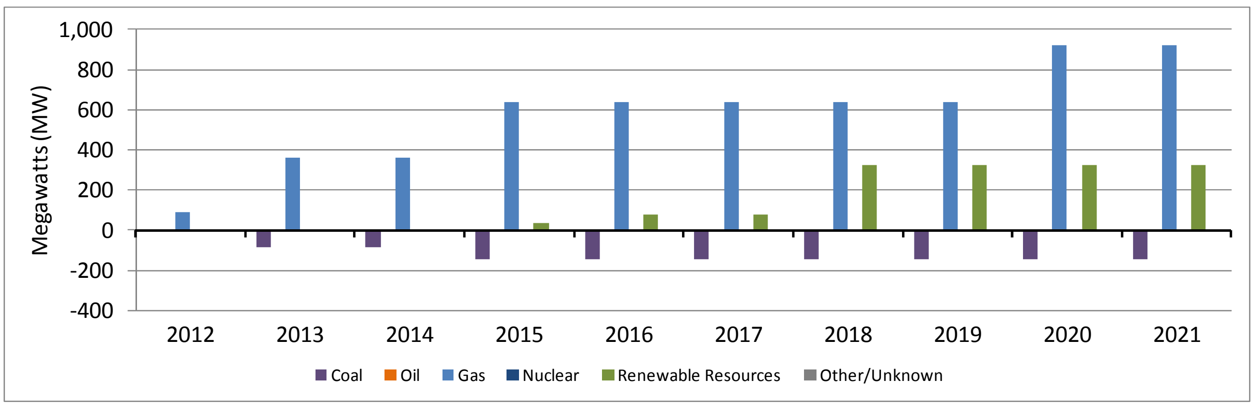


Figure 90: Annual Net Capacity Change by Fuel Type



Approximately 4,000 MW of Existing capacity resources and 1,500 MW of Future capacity resources are expected to be in-service through the assessment timeframe. However, some of the Existing capacity resources will be reduced through unit retirements (approximately 265 MW) over the assessment timeframe. Of this amount, approximately 198 MW of nameplate capacity is existing wind and 175 MW of nameplate capacity is future wind capacity. For reliability purposes, Saskatchewan considers 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak. This is equivalent to 19.8 MW of existing wind and 17.5 MW of future wind capacity during the summer period, and 39.6 MW of existing wind and 35 MW of future wind capacity during the winter period. There are no biomass or *Conceptual* resources in Saskatchewan (Table 75).

Table 75: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	40	75	35
	Derated	158	298	140
	Wind - Total Nameplate Capacity	**198**	**373**	**175**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	850	1,142	292
	Derated	2	2	-
	Hydro - Total Nameplate Capacity	**853**	**1,145**	**292**
Biomass	Expected	-	-	-
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**-**	**-**	**-**

SaskPower has a legislated obligation to serve, and as such Future resources are considered in determining the capacity requirements to meet Saskatchewan's reliability criteria. Future resources are included based on economically optimized expansion sequences to serve the load. Saskatchewan does not plan for *Conceptual* resources.

Capacity Transactions

Saskatchewan has no Firm imports scheduled from other Assessment Areas for either seasons between 2011 and 2021.

Saskatchewan has a Firm export of 50 MW to other Reporting Areas scheduled for the June to September period in 2011 (Table 76). No partial path reservations or LDCs are involved. 100 percent of the energy contract is Firm and has Firm transmission reserved. SaskPower only has Firm contract exports through September 30, 2011, for the rest of this assessment period there are no Firm contracted imports.

Table 76: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	-	-	-	-
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**-**	**-**	**-**	**-**
Exports	Firm	50	-	-	-
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**50**	**-**	**-**	**-**
	Net Transactions	**(50)**	**-**	**-**	**-**

Transmission

A number of transmission reinforcements and various transformer and substation expansions and upgrades are projected to be completed during this assessment period. The following projects have been identified to maintain reliability.

- Planned addition of two 230-138 kV auto-transformers in the Tantallon area (eastern Saskatchewan) in late 2012 to meet transmission adequacy in the area for projected load growth.
- Planned addition of 56 miles of 230 kV transmission line in the Saskatoon-Wolverine area (central Saskatchewan) in late 2013 to meet transmission adequacy in the area for projected load growth.
- Planned addition of a 230-138 kV auto-transformer in the Peebles area (eastern Saskatchewan) in late 2013 to meet transmission adequacy in the area for projected load growth.
- Planned addition of 230-138 kV auto-transformers in the Boundary Dam area (south-eastern Saskatchewan) in late 2013 to meet transmission adequacy in the area due to potential generation retirements.
- Planned addition of 62 miles of 230 kV transmission line in the Peebles-Tantallon area (eastern Saskatchewan) in late 2015 to meet transmission adequacy in the area for projected load growth.
- *Conceptual* addition of 37 miles of 230 kV transmission line in Regina-Pasqua area (south-central Saskatchewan) in late 2015 to meet transmission adequacy in the area for projected load growth.
- *Conceptual* addition of two 230-138 kV auto-transformers in the Regina area (south-eastern Saskatchewan) in late 2014-2015 to meet transmission adequacy in the area for projected load growth.
- *Conceptual* addition of 96 miles 230 kV transmission line in the Beatty-Wolverine area (north-central Saskatchewan) in late 2016 to meet transmission adequacy in the area for projected load growth.

There are no reliability concerns in meeting target in-service dates of the transmission projects. However, if projected load growth occurs and meeting the in-service dates for planned transmission facilities become an issue, load will be treated as non-Firm and remedial action schemes may be installed in lieu of the planned bulk power transmission facilities until such facilities are in-service. Generation retirements will be coordinated with planned facility additions.

With planned facilities in-service, Saskatchewan does not expect any major transmission and/or transformer constraints that could significantly impact reliability. Other significant substation equipment planned to be in service in the 2011 through 2021 planning horizon are as follows:

- Planned addition of a SVC in the Pasqua area (south-central Saskatchewan) in late 2013 to meet transmission adequacy in the area.
- Planned addition of a SVC in the Swift Current area (south-western Saskatchewan) in late 2013 to meet transmission adequacy in the area.

Operational Issues

No systemic generating unit or transmission outages are expected in Saskatchewan that will impact reliability. Operating guides are developed on an ongoing basis to deal with facility outages.

If peak demands are higher than expected, resource adequacy would be offset by planning reserves and external markets. If necessary, operational measures included in Saskatchewan's emergency operation plans include interruptible load contracts, public appeals, and rotating outages. There are no environmental or regulatory restrictions that have been identified at this time that could potentially impact reliability in Saskatchewan. Saskatchewan does not anticipate any operational changes resulting from integration of variable resources.

There are no known operational concerns resulting from generation connected to the distribution system. Saskatchewan does not expect any reliability concerns resulting from high-levels of Demand Response resources. Protection systems are maintained and tested on an on-going basis, and misoperations are evaluated for lessons learned.

Emerging and Standing Reliability Issues

Greenhouse Gas Regulations

Timeframe

- The impact of the greenhouse gas regulatory issue is currently uncertain and is expected to be clarified in the short-term. The consequence of the reliability issue is expected to be long-term.

Emerging or Standing Issue

- Saskatchewan considers greenhouse gas regulations to be an emerging issue.

Changes to Reference Case

- None.

Projected Long-Term Impacts

- In the 10-year horizon, Saskatchewan may choose to retire existing units and replace them with generating units that emit less greenhouse gases or retrofit them to reduce emissions.

Regional Reliability Impacts

- The impact of greenhouse gas regulations is not expected to impact Saskatchewan's reliability.

Resource Adequacy Considerations

- The issue of greenhouse gas regulations could potentially impact Saskatchewan's resource adequacy if enough lead time was not provided to retrofit or replace current generating with generating units that emit less greenhouse gases. However, it is anticipated that Saskatchewan will have sufficient time to respond to future greenhouse gas regulations.

Transmission Adequacy Considerations

- None.

Resource Development Issues

- None.

Operational Impacts

- None.

Additional Information

Greenhouse gas regulation is expected to become an issue in the short-term (1 to 5 year timeframe) as specific regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability because it is anticipated that enough lead time will be given to allow for appropriate mitigation. Saskatchewan currently relies, in part, on greenhouse gas emitting generation sources such as coal and natural gas. The potential impact of greenhouse gas regulations would be to reduce Saskatchewan's ability to rely on carbon emitting fuel sources for future generation requirements. Saskatchewan has developed future scenario plans to deal with anticipated greenhouse gas emission regulations. Saskatchewan has not yet experienced any reliability issues related to greenhouse gas regulations, and is expected to effectively mitigate any future reliability issues related to greenhouse gas regulations. Mitigation will either be reducing greenhouse emissions or replacement of generation.

Assessment Area Description

SaskPower is the Balancing Authority for the province of Saskatchewan. Saskatchewan is a province of Canada and comprises a geographic area of 251,700 sq miles and approximately 1 million people. Peak demand is experienced in the winter.

NPCC-Maritimes

Introduction

The Maritimes Area is a winter-peaking subregion of the NPCC Assessment Area. It is comprised of the Canadian provinces of New Brunswick (NB, Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of the state of Maine, which is radially connected to the New Brunswick power system.

The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area and the Balancing Authority for the NB, PEI, and northern Maine sub areas. Nova Scotia Power Inc. (NSPI) is the Balancing Authority for Nova Scotia. NBSO submits Long-term Resource Adequacy (LTRA) data to NERC for the Maritimes Area.

Because of the relative size of the Area's largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Generators use a diverse mix of fuel types with the result that the area is not overly reliant on any particular fuel to meet its load. The area is strongly interconnected with neighboring areas via high capacity transmission lines but is not dependant on these areas to supply area load. As a result, LTRA analysis reveals that even with reasonable foreseeable contingencies including load forecast uncertainty, fuel disruptions, and generator and transmission interruptions, Maritimes Area load will be reliably supplied for the 10-years covered in this report.

The forecasted peak demand of the Maritimes Area for the 2011-2012 winter of 5,668 MW is projected to decline marginally to 5,579 MW by 2021-2022. Similar to last year the forecast, the average annual growth rate is effectively flat. Existing capacity resources for 2011-2012 total 7,936 MW, of which 6,402 MW are certain. This includes installed wind generation of 780 MW with 314 MW expected on-peak. *Existing-Certain* resources are practically unchanged since last year. Major capacity changes expected in 2012 are the retirement of 299 MW at the Dalhousie Generating Station in May and the return to service of the refurbished 660 MW Point Lepreau generating station in October. Installed wind generation is planned to grow by 173 MW by 2021-2022 driven by renewable energy targets in the various subareas. During the Area's winter peak load periods both the Anticipated Resources and Adjusted Potential Resources Reserve Margins for the Maritimes Area are 20 percent in 2011 and exceed 27 percent for the remainder of the assessment time frame, thus exceeding the NERC 15 percent Reference Margin Level in all years.

Three major new transmission line additions are in conceptual stages during the review period. In New Brunswick, a new 345 kV circuit between the Coleson Cove and Salisbury terminals is being considered to improve transmission service to Southeastern NB which has experienced relatively higher load growth versus the remainder of the province. New Brunswick and Nova Scotia are studying a project to twin the existing 100 mile 345 kV transmission line between Salisbury, New Brunswick and Onslow, Nova Scotia. This project is under study for 2016 and will allow for increased integration of renewable energy in the Maritimes Area. In the following year, potential development of the Lower Churchill Generation Project in the Canadian province of Newfoundland and Labrador would see the installation of a High Voltage Direct Current (HVDC) undersea cable link between that province and Nova Scotia. This would provide a transmission path from this new source to markets in the Maritimes and New England.

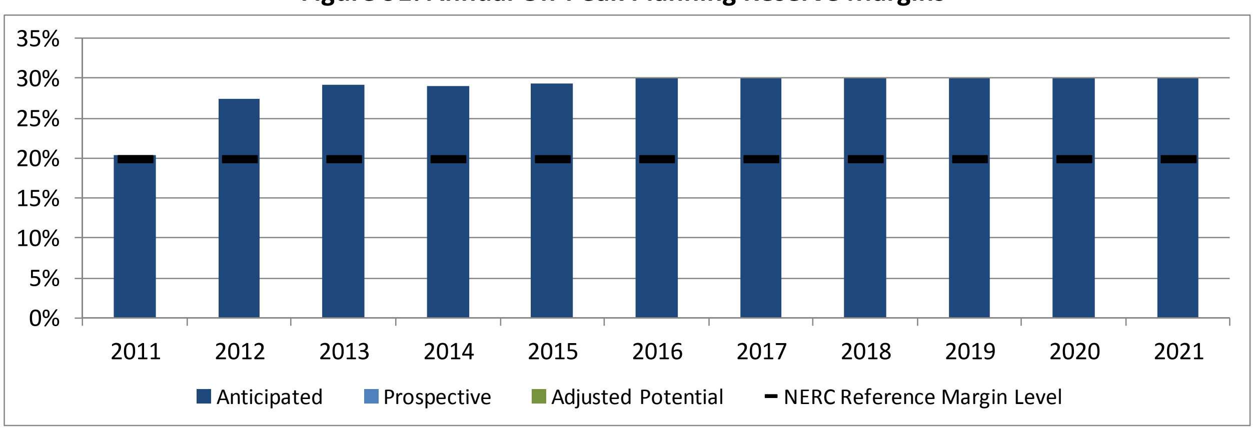
Apart from the above, there are no significant generating unit outages, transmission additions, or temporary operating measures that are anticipated to impact the reliability of the Maritimes during the next 10-years.

Reliability Assessment

For each year of the forecast, the Reserve Margin of the Maritimes Area exceeds 34 percent. The Maritimes Area uses a reserve criterion of 20 percent for planning purposes and it was shown in the "2010 Maritimes Area Comprehensive Review of Resource Adequacy[221]" that adherence to this reserve criterion complies with the NPCC reliability criterion that the probability of disconnecting Firm load due to resource deficiencies -its Loss of Load Expectation or LOLE- shall be no more than 0.1 days per year. The Maritimes Area Reserve Margins and the associated target used for NPCC regional comprehensive reviews differ from LTRA Reserve Margins in that the former are not required to cover interruptible load.

In its 2010 Maritimes Area Comprehensive Review of Resource Adequacy it was shown that the NPCC reliability criterion of no more than 0.1 days of Firm load disconnections per year is not exceeded by the Maritimes Area for all years in the 2011-2015 study period, and varies between 0.002 to 0.037 days per year for the base-load forecast. The Maritimes Area required no support from its interconnections to meet the NPCC reliability criterion for all years of the 2011-15 study. The Maritimes Area was also shown to adhere to its own 20 percent reserve planning criterion in all years for the base-load forecast, with reserve levels varying between 24 percent and 36 percent (Figure 91).

Figure 91: Annual On-Peak Planning Reserve Margins



The Maritimes Area is forecast to have sufficient resources to meet its 20 percent reserve requirement for each of the 10-years of this assessment. No additional internal or external resources are required and the Area does not participate in any regional reserve sharing program with neighboring areas.

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

There are no differences between short- and long-term capacity requirements in the Maritimes Area. Any distributed resources are netted against load and not counted as capacity in the Maritimes Area. Scenarios of high load growth and zero wind availability were studied in the 2010 Maritimes Area Comprehensive Review of Resource Adequacy with the result that the Maritimes Area, even under these conditions, was still able to meet its 20 percent reserve criterion in all cases with no more than 73 MW of necessary interconnection support. This level of interconnection support represents only 5 percent of the Maritimes Area tie benefits capability.

Wind capacity required to meet each sub area's renewable generation mandates has been included in the resource planning process using capacities derived from appropriate estimated or experienced capacity factors for periods studied. All generation projects connecting to the transmission grid, including wind, must undergo a System Impact Study (SIS) and satisfy all connection requirements determined by the SIS and local grid code. Wind projects are required to transmit atmospheric data (wind speed, wind direction, temperature) to the local System Operator for wind forecasting needs. Demand Response in the Maritimes Area consists primarily of interruptible customer load equivalent to 7 percent of peak load for 2011-2012. Performance of these customers is metered in real-time to ensure compliance with operator instructions. There are no unit retirements in this assessment that significantly impact the reliability of the Maritimes Area.

At this time, there are no plans to install more UVLS in the Maritimes Area. Collectively, UVLS in New Brunswick can shed up to 25 percent of load. Under Frequency Load-Shedding (UFLS) in the Maritimes Area will conform to NPCC Directory 12 requirements calling for 27 percent of Area load available to be shed by 2011 rising to 30 percent by 2012. Neither UVLS nor UFLS are used in resource adequacy analysis. There are no plans for additional SPS schemes in the Maritimes Area in this assessment.

The Maritimes Area has no Energy-Only or transmission-limited resources. Transmission constraints are modeled in LOLE studies. 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 impact of a complete loss of natural gas fuel for two summer months with a simultaneous complete loss of all power from wind facilities is modeled as an extreme event in NPCC Summer Resource Adequacy assessments. The complete loss of wind output at higher winter capacity factors is the extreme event modeled for the NPCC Winter Resource Adequacy assessments.

NPCC has established a Reliability Assessment Program to bring together work done by the Council, its member systems and Areas relevant to the assessment of bulk power system reliability. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the reliability of the planned bulk power transmission system of each Area of NPCC and the transmission interconnections to other Areas. The purpose of these reviews is to determine whether each Area's planned bulk power transmission system is in conformance with the NPCC Regional Reliability Reference Directory #1, *Design and Operation of the Bulk power system* (adopted: December 1, 2009).[222] Since it is NPCC's intention that its criteria be consistent with the NERC *Planning Standards*, conformance with the NPCC criteria assures consistency with the NERC *Planning Standards*.

The Transmission Review for 2010 was an Intermediate level, covering to the year of 2015. The results of this study concluded that the Bulk power system for the Maritimes Area remains in conformance with Directory #1. There are no reactive power-limited areas on the bulk power system for the Maritimes Area. Voltages on the system are operated between 0.95 and 1.05 per unit (p.u.) during normal conditions and between 0.9 and 1.1 per unit (p.u.) during single contingencies on the system. No new FACTS or "smart grid" devices are planned for the Maritimes Area bulk power system during the assessment period.

There are no significant smart grid programs forecast for the Maritimes Area over the next 10-years. However, in view of the increasing amount of variable generation sources, particularly the use of wind resources, the technology is being investigated as a means of balancing loads and resources in the Area with greater efficiency.

There are no expected changes in environmental regulations that will affect area reliability. Renewable Portfolio Standards in the area have mandated increased levels of wind generation in the area and these have been included in resource adequacy reviews. The Maritimes Area examines cases where a complete absence of wind in the area occurs due to weather conditions and has concluded that the area is not overly reliant on wind generation to meet its 20 percent reserve criterion a level at which it has been shown to meet the NPCC resource adequacy reliability criterion. Finally, there are no project slowdowns, deferrals, or cancellations that affect reliability in the Maritimes Area during this long-term assessment period.

Demand

The forecast average annual on-peak demand growth rate is -0.14 percent from 2011-2021 (Table 77).

Table 77: Peak Season Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	5,668	5,579	(89)	-0.14%	-1.6%
Net Internal	5,298	5,255	(43)	-0.07%	-0.8%

Separate demand and energy forecasts are prepared by each Maritimes Area jurisdiction, 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.

222 http://www.npcc.org/documents/regStandards/Directories.aspx.

The load forecast for New Brunswick is based on 30-year average of the Heating Degree Days in each month from the winters of 1980-1981 through 2009-2011, with the annual peak hour demand determined for a design temperature of -24°C over a sustained 8-hour period. It is prepared based on a cause and effect analysis of past loads, combined with data gathered through customer surveys, and an assessment of economic, demographic, technological and other factors that affect the utilization of electrical energy.

The load forecast for Nova Scotia is based on a long-term average of temperatures at time of peak, 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 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 load forecast for northern Maine is based on historic average peak hour demand patterns. The 2010 peak was inflated at a nominal rate of 0.5 percent. Monthly peak forecasts for the Maritimes Area are summations of the individual jurisdiction forecasts. The peak is therefore non-coincident. For Area studies, the individual forecasts are combined using the load shape of each jurisdiction. All jurisdictions in the Maritimes Area are winter peaking due to high electric heating load. Long-term resource evaluations are based on a 20 percent Reserve Margin above the forecast Firm winter peak load.

Current and projected Energy Efficiency effects are incorporated directly into the load forecast for each of the areas. For New Brunswick and Prince Edward Island, the responsibility for Demand Side Management initiatives including forecasts and verification now belongs to provincial government agencies. In Nova Scotia, the DSM administrator is Efficiency Nova Scotia Corporation (ENSC), a non-government, non-profit organization responsible for developing and implementing Energy Efficiency programs. ENSC retains an evaluation consultant to independently evaluate both process and savings impacts of the programs. Additionally, the Nova Scotia Utility and Review Board both retain an independent savings verification consultant to verify the savings reported by the independent evaluation consultant. Energy Efficiency and DSM programs are shown below for the NPCC-Maritimes Assessment Area (Table 78).

Table 78: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**-**	**-**	**-**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	371	324	(46)
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**371**	**324**	**(46)**
Total Demand-Side Management	**371**	**324**	**(46)**

One of the Demand Response programs currently used in the Maritimes Area but most predominantly in Nova Scotia is interruptible demand. For 2011-2012, the interruptible demand forecast for the peak month is 371 MW, which represents 7 percent of the peak demand forecast. Other Demand Response programs used in Nova Scotia are primarily rate design-driven and along with interruptible pricing for large industrials, include time of day pricing for residential customers with electric thermal storage home heating equipment, and the Extra Large Industrial Interruptible two part Real-time Pricing rate for NSPI's two largest customers. In Nova Scotia, a 5 percent voltage reduction is implemented at selected substations (approximately 1-5 MW). Interruptible demand is reported separately but other programs are incorporated directly into the load forecast. In Nova Scotia, it is anticipated that more future Demand Response programs might be contemplated by the DSM administrator but none have yet been planned.

While demand side management resources are considered for meeting regional targets for greenhouse gas reductions, they are not currently counted towards regional renewable portfolio standards.

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 has 6,402 MW of *Existing-Certain*, 0 MW of *Existing-Other* and 0 MW of *Existing-Inoperable* capacity resources in 2011-2012. The *Existing-Certain* value expects 314 MW of wind, 1,329 MW of hydro, and 96 MW of biomass capacity to be present on-peak out of total variable capacities of 780 MW, 1,330 MW, and 98 MW respectively.

The on-peak capacity mix and annual net change by fuel type can be seen below (Figure 92 and Figure 93).

Figure 92: On-Peak Capacity Mix by Fuel Type

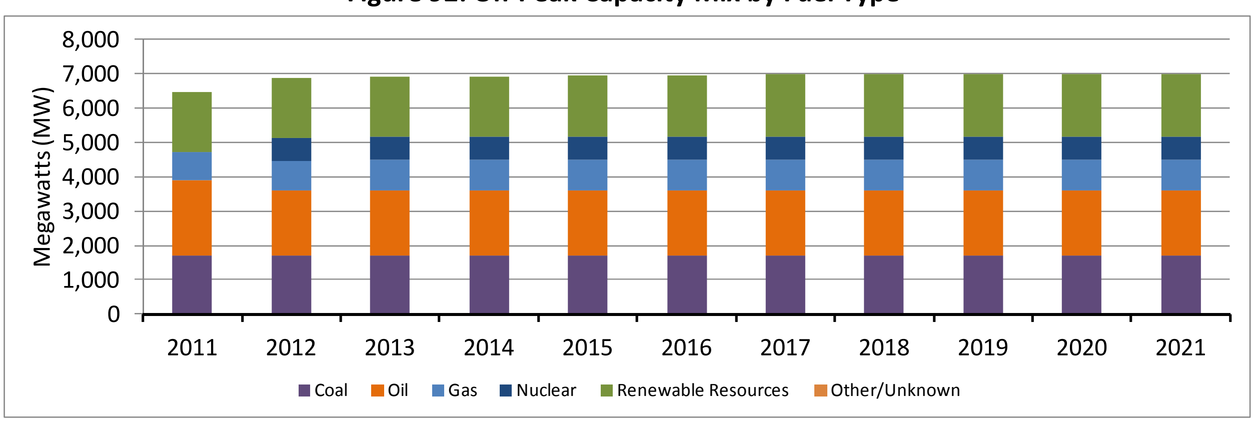
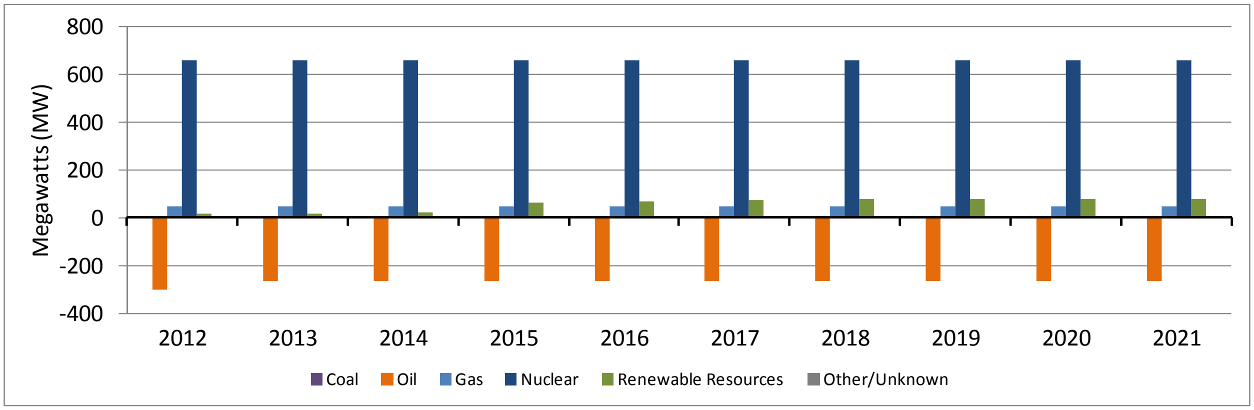


Figure 93: Annual Net Capacity Change by Fuel Type



Prior to the peak during the winter of 2012-2013, completion of the refurbishment of the Point Lepreau nuclear generating station will return 660 MW of operating capacity to the system. In addition, as of January 2013 major a combustion turbine is expected to return to service in Nova Scotia adding 33 MW back into operating system resources. New *Future-Planned* additions during the study period include 49 MW from the addition of a steam cycle to two combustion turbines in Nova Scotia (before the 2011-2012 peak), 173 MW of wind resources, and 35 MW of biomass projects, all planned to be in service before January 2018. Another 40 MW of wind resources identified as *Conceptual* in the PEI area could be installed prior to January 2013.

Wind project capacities modeled in resource adequacy calculations for New Brunswick and northern Maine (40 percent of nominal capacity during the winter peak period) are based on results from the September 2005 NBSO report, "Maritimes Wind Integration Study."[223]

This report showed that the effective capacity from wind projects, and their contribution to LOLE was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. In PEI wind capacity was based on actual capacity factors for the wind generators during winter and summer peak load periods. In Nova Scotia, the capacity contribution of wind projects during the peak is based on a three year rolling average of the winter peak period actual capacity factor (combined with the annual forecasted capacity factor, if in service less than three years). This is based on an agreed formula between the Renewable Energy Industry Association of Nova Scotia and NSPI. New Nova Scotia wind resources are assigned an on-peak capacity based on the forecast winter capacity factor. Projections for on-peak expected capacity and derates for the NPCC-Maritimes Assessment Area are shown below (Table 79).

[223] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf.

Table 79: On-Peak Expected and Derated Renewable Resources

	Renewable Resource	2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	314	355	42
	Derated	467	597	131
	Wind - Total Nameplate Capacity	**780**	**953**	**173**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	1,329	1,333	4
	Derated	2	2	-
	Hydro - Total Nameplate Capacity	**1,331**	**1,335**	**4**
Biomass	Expected	96	131	35
	Derated	2	2	-
	Biomass - Total Nameplate Capacity	**98**	**133**	**35**

There are no significant increases in distributed generation identified in the Maritimes Area except in Nova Scotia. Existing distributed resources are netted against load and not counted as capacity. In Nova Scotia, increased amounts of renewable generation will be connected to the distribution system through the Community Feed-in-Tariff as outlined in the Province's Renewable Electricity Plan in April 2010. Further study will be required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.

Capacity Transactions

The Maritimes Area has a total supply of 366 MW of capacity contracted from Québec for the 2011-2012 peak. There are currently no capacity imports scheduled after that time. None of the capacity imports for the Maritimes Area are related to Reserve Margins or tied to specific generating units.

Until October 2011, there is a Firm capacity sale of 200 MW from the Maritimes to Hydro Québec. This sale is tied to two 100 MW oil combustion turbines at Millbank, NB. This sale is also backed up by a transmission reservation.

Transmission

NB Power is planning to add a new 1 mile 138 kV line in late 2011 to serve distribution load in the Newcastle area of the province. Nova Scotia is planning the following 138 kV transmission line projects:

- Near Canaan Rd - this line is 27 miles in length, and targeted for 2011
- Near New Minas - this line is 4 miles in length, and targeted for 2012
- Near Eastern Passage - this line is 7 miles in length, and targeted for 2013

Regarding *Conceptual* projects, New Brunswick is currently studying a 103 Mile 345 kV transmission line project between Coleson Cove New Brunswick and Salisbury NB twinning an existing circuit to better serve growing loads in southeastern NB. An interprovincial tie line from Salisbury NB to Onslow NS could allow for more renewable generation sources to be incorporated into the Maritime generation mix and increase the tie capacity allowing for better sharing of reserves. This line would be 100 miles in length, and targeted for 2016. Potential development of the Lower Churchill Generation Project in the

Canadian province of Newfoundland and Labrador would see the installation of a High Voltage Direct Current (HVDC) undersea cable link between that province and Nova Scotia. This would provide a transmission path from this new source to markets in the Maritimes and New England. On Prince Edward Island a new 13 mile 138 kV line is being studied to help accommodate a conceptual 30 MW wind farm located in the eastern part of the province.

The projects described above will improve reliability but are not being proposed specifically for this reason. Moreover, there would be little impact on reliability if they were delayed. There are no transmission constraints in the Maritimes Area affecting reliability and no other significant substation equipment additions are planned for the Maritimes Area within this long-term assessment period.

Operational Issues

No significant generating unit outages, transmission additions or temporary operating measures are anticipated that would impact the reliability of the Maritimes during the next 10-years.

In its "2010 Maritimes Area Comprehensive Review of Resource Adequacy"[224], scenarios of high load growth and zero wind availability were studied, with the result that the Maritimes Area was still able to meet its 20 percent reserve criterion in all cases with no more than 73 MW of necessary interconnection support. This level of interconnection support represents only 5 percent of the Maritimes Area tie benefits capability.

There are no environmental or regulatory restrictions foreseen that could potentially impact the reliability of the Maritimes Area. Plans are underway for the individual jurisdictions within the Maritimes Area to coordinate the sharing of wind data and possibly wind forecasting information and services.

In Nova Scotia, the Department of Energy (DOE) released its Renewable Electricity Plan in April 2010, which sets out the Province's commitment to renewable electrical energy supply (including variable/intermittent resources). The 2008 Hatch Ltd. Wind Integration Study[225] identified and assessed the effects of integrating large scale wind power generation into Nova Scotia's electric power system. This study confirmed that "more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure". NSPI is presently commencing work on a 2011-2012 wind integration study.

There are no operational changes or concerns resulting from distributed resource integration in the Maritimes Area other than in Nova Scotia where as increased amounts of renewable generation are connected to the distribution system, further study will be required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.

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

[225] http://www.gov.ns.ca/energy/resources/EM/Wind/NS-Wind-Integration-Study-FINAL.pdf.

No reliability issues are anticipated from Demand Response resources for the Maritimes Area. These consist mainly of interruptible customers totaling 7 percent of peak demand in 2011-2012.

All relay protection misoperations are investigated and if the relay is found to be faulty, it is replaced. If the settings are found to be in error, they are corrected. If human error was the cause (accidental trips etc.), the staff involved is trained to avoid the problem in the future. If the relay is misapplied, a new relay scheme would be installed to the correct the problem. All of these should work to reduce the potential for future misoperation.

Emerging and Standing Reliability Issues

Increasing Southeastern New Brunswick Load

Timeframe

- Mid-term - 4 to 8 years.

Emerging or Standing Issue

- Emerging.

Changes to Reference Case

- The issue is load related but should not affect resource adequacy. LTRA is unaffected.

Projected Long-Term Impacts

- Line overloads during contingencies and degraded voltages are possible affects within 10 years.

Regional Reliability Impacts

- The effects are localized to southeastern NB and are not related to reliability unless delays occur.

Resource Adequacy Considerations

- The issue is load related but should not affect resource adequacy. The increasing loads are already accounted for in forecasts.

Transmission Adequacy Considerations

- Line overloads during contingencies and degraded voltages should localized to southeastern NB area as well as reduced tie transfer capabilities within the sub area.

Resource Development Issues

- Resource development in southeastern NB would more likely mitigate rather than exacerbate this issue.

Operational Impacts

- Both line overloads during contingencies and degraded voltages would be mitigated by the construction of a potential new 345 kV circuit between the Coleson Cove and Salisbury terminals in NB.

Additional Information

Load growth in the southeastern area of New Brunswick has been more rapid than other areas in the province and the transmission system supplying the area may need to be reinforced within the midterm time frame between 4 and 8 years hence. This is classified as an emerging issue that will not affect resource adequacy as the effects are localized and the loads are accounted for in forecasting. The issue could affect transmission adequacy and create operating problems in the local area by causing circuit overloads for contingencies, degrading area voltages and reducing tie transfer capabilities within the sub area. These impacts would be moderate but not likely to create problems in neighboring regions. The interconnection of resources in the area is not considered an issue for the area and would likely help mitigate this emerging issue as a lack of generating resources situated in this area contributes to the problem. No reliability or operational problems have been experienced to date however, if the system begins to experience operational problems related to the growing loads, delays in the project would eventually create unacceptable operating conditions and could eventually require load shedding. To address this issue, construction of a new 103 mile long 345 kV transmission line twinning existing circuits is being considered between the Coleson Cove NB and Salisbury NB terminals. The new line would increase the transmission capacity in the area alleviating contingency related overloads and improving area voltages.

Additional Renewable Resources

Timeframe

- Mid-term - 4 to 8 years.

Emerging or Standing Issue

- Emerging.

Changes to Reference Case

- There are no indications that existing generation will be retired prematurely. LTRA should not be affected.

Projected Long-Term Impacts

- Increasing variable generation will require greater ability to balance loads between sub areas.

Regional Reliability Impacts

- The issue is not expected to impact regional reliability.

Resource Adequacy Considerations

- Because new generation is being added without corresponding retirements at this time, resource adequacy measures should improve.

Transmission Adequacy Considerations

- Transmission enhancements are not related to transmission contingencies or inadequacies, but rather to the lack of transfer capability related to increased operation of large amounts of variable resources.

Resource Development Issues

- Variable resources transfer balancing issues to the transmission system. Any delays in transmission enhancements could delay resource development.

Operational Impacts

- Increasing variable generation will require more balancing capability. Overloads are not expected to occur since adequate transmission would be required prior to installation of new generation. The new generation could either improve or degrade local voltages. The proposed new Salisbury NB to Onslow NS line could benefit southeastern NB transmission supply.

Additional Information

The increasing amounts of renewable energy resources being developed across the Area, particularly in Nova Scotia, may create a need for bulk power system enhancements within the midterm time frame between 4 and 8 years hence. Nova Scotia's Renewable Energy Standard (RES) is seeking to displace significant amounts of fossil fuelled generation with renewable resources. By 2015, 25 percent of the provinces electricity sales will be supplied by renewable energy sources and by 2020, 40 percent is targeted. Given the variable nature of most renewable energy resources and the potential at times to produce more energy than can be used by an area or too little, there will be frequent operational needs to balance the capacity and loads. Given the size of the increase in renewable resources, this may require bulk power system enhancements between sub-areas in the Maritimes. This is an emerging issue that is not related to resource or transmission adequacy except that the lack of transmission enhancement could delay the development of new renewable resources. In fact, because new generation is being added without corresponding retirements at this time, resource adequacy measures should actually improve as this issue materializes. To address this issue, a new 100 mile long 345 kV tie circuit is being assessed for possible development between the Salisbury NB and Onslow Nova Scotia terminals. No reliability or operational problems have been experienced to date and the new line would not be expected to impact either in a significant way. The impact of any delays would be minimal and economic in nature and no neighboring regions would be affected. Side benefits of the line construction would be reinforcement of the transmission system around southeastern NB but the main benefit would be timely integration of the planned renewable resources.

Assessment Area Description

The Maritimes area encompasses four winter peaking system operators and covers an area of approximately 55,000 square miles and a population of approximately 1.9 million people. The four system operators in this Assessment area are New Brunswick System Operator (NBSO), Nova Scotia Power (NS Power), Maritime Electric, and Northern Maine ISA (Table 80).

Table 80: Maritimes Assessment Area

Jurisdiction	System Operator	Peak Season	Square Miles	Population
New Brunswick	NBSO	Winter	28,000	750,000
Nova Scotia	NS Power	Winter	21,000	940,000
Prince Edward Island	Maritime Electric	Winter	2,200	140,000
Northern Maine	Northern Maine ISA	Winter	3,600	90,000

NPCC-New England (ISO-NE)

Introduction

For this *2011 Long-Term Reliability Assessment*, ISO New England Inc. (ISO-NE) forecasts no major reliability issues with respect to fuel supply, availability of both supply or demand-side resources, or the capability of the regional transmission system to serve the projected seasonal peak demands and energy requirements of the six-state New England subregion.

New England, a subregion of NPCC, is a summer-peaking system. The 2010 summer actual peak demand was 27,102 MW which was 88 MW lower than the last year's 2010 LTRA projection for the 2010 summer peak demand of 27,190 MW. A warmer than normal 2010 summer season in New England produced several peak demand days.[226] The Total Internal Demand[227] projected for the 2011 summer is 27,550 MW and is 31,215 MW for the 2020 summer. This year's forecast of the ten-year (2011-2020) 50/50 summer peak demand compound annual growth rate is 1.4 percent.

For the 2011 summer, the *Existing-Certain* capacity totals 29,590 MW which is 763 MW lower than last year's value of 30,353 MW when demand resources are not included. Approximately 437 MW of Future Capacity Additions are projected to be commercialized by the 2021 summer. In addition, demand resources are expected to grow by 1,364 MW over the current capacity of 2,035 MW. The only significant retirement of regional capacity is the submittal of a non-price retirement for the entire Salem Harbor station, currently rated at approximately 745 MW.[228] Salem Harbor units 1 & 2 (158 MW) are scheduled to retire by the end of 2011. Salem Harbor 3 & 4 (587 MW) are scheduled to retire by June 1, 2014. ISO-NE and regional Transmission Owners have been studying this retirement. To ensure the continued reliability of the electric system within northeastern Massachusetts, transmission enhancements are under investigation for expedited installation.[229]

The NERC reference Reserve Margin for a thermal power system like New England is 15 percent; however, New England does not have a target Reserve Margin. New England's 2011 summer Anticipated Reserve Margin is 18.9 percent, which is 3.9 percent above the NERC reference Reserve Margin. This Reserve Margin remains above the 15 percent reference Reserve Margin through 2014 and then begins to decrease, reaching a low of 3.4 percent in 2021. Based on the forecast of the subregion's Net Installed Capacity Requirement (Net ICR) for 2020, it is estimated that New England's 2020 summer Reserve Margin would be no lower than 14.2 percent.

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[226] June, July and September 2010 were warmer than normal, and August 2010 was cooler than normal.

[227] All items in italics reference the specific line item title within the associated NERC spreadsheet, with the exception of report titles.

[228] Salem Harbor has three coal-fired units (#1, #2 & #3) at a combined rating of 308 MW and one oil-fired unit (#4) rated at 437 MW.

[229] For more information on the retirement of Salem Harbor, reference: http://www.iso-ne.com/pubs/spcl_rpts/2011/salem_harbor_npr_summary_05102011.pdf

ISO-NE's Regional System Plans (RSPs) identify the subregion's needed transmission improvements over a ten-year period. The current plan builds on the results of previous RSPs and other regional activities. The transmission projects have been developed to coordinate major power transfers across the system, improve service to demand, and meet transfer requirements with neighboring balancing authority areas. The only significant transmission project that has been placed in service since the prior year is the Vermont Southern Loop 345 kV line.

Transmission plans continue to be developed to serve demand growth throughout the New England subregion. ISO New England has identified projects that address transmission system performance issues, either individually or in combination. Some of the projects address subregional reliability issues and also have the ancillary benefit of improving the performance of major transmission corridors and thus the overall performance of the system. These transmission projects are identified in detail in Appendix VI of this assessment. Transmission projects are developed to serve the entire New England subregion reliably and are fully coordinated with other regions.

Over the course of the assessment period, the most significant issues facing New England have been to maintain the general performance of the long 345 kV corridors, maintain the reliability of supply to serve demand, and develop the transmission infrastructure to integrate generation throughout New England. The region faces thermal and voltage performance issues, stability concerns, and is reliant on several Special Protection Systems (SPS) that may be subject to incorrect or undesired operation. System upgrades, which are either in progress or have been recently completed, provide significant relief for these areas.

This assessment identifies five issues that could possibly impact future system reliability. These are categorized into the short and long-term timeframes. The short-term challenges involve (1) resource performance and flexibility, and, more specifically, the uncertain performance of aging supply-side resources, the uncertain performance of new demand resources, and lack of comparability between new demand-side and supply-side resources. The failure of resources to perform and concerns over system flexibility also heightens concerns about fuel diversity. Specifically, (2) increased reliance on natural gas-fired capacity poses a risk to the New England electric system, as sufficient natural gas may not be available during periods of very high seasonal demand (winter) or when the regional natural gas transportation system is experiencing problems.

The longer-term challenges are the result of significant changes to New England's power system which will be driven by (3) the retirement of fossil-fired generators, which is likely as a result of economic factors and environmental regulations, and (4) the integration of a greater level of variable resources, primarily renewable (*i.e.,* wind and solar) energy resources. In addition, the ISO and some stakeholders have noted that wholesale markets may not adequately reflect the rapidly-evolving reliability needs that are identified through reliability planning and system operations, and that better (5) alignment of planning and markets could create more opportunities for market resources to meet reliability needs, thereby more efficiently managing accelerated resource turnover.

ISO New England has developed a sequence of solutions to address these challenges. The first stage of the solution includes enhancing resource performance and accountability, improving system reserves and flexibility, and implementing changes to ensure that resource attributes properly reflect constraints that may limit availability or performance. The second stage of the solutions, which would be addressed over a longer time frame, involves establishing methods for identifying and evaluating in a consistent manner, the various potential transmission, generation, and demand solutions for identified reliability needs. ISO New England would also make design improvements to its capacity and reserve markets to procure resources with more precision in particular geographical areas or with desired characteristics. Finally, a process would be established for regularly evaluating and identifying the level of required deliverability and diversity in the resource mix, and how such needs could be translated into capacity and reserve market product definitions and performance requirements.

ISO-NE is the Regional Transmission Organization (RTO) for the six-state New England subregion. ISO-NE is responsible for the reliable operation of the bulk power system, administration of the region's wholesale electricity markets, and management of the comprehensive planning process. Within the Northeast Power Coordinating Council Inc. (NPCC), ISO-NE is the Balancing Authority for the New England subregion.

This assessment identifies issues that could possibly impact future system reliability within New England. A quantitative assessment of New England's long-term forecast for Demand, Capacity, Imports and Exports, and Transmission is provided for those respective sections. The resultant capacity margins and corresponding percentages are a result of populating the associated NERC spreadsheet, which uses a deterministic approach to forecasting New England's long-term reliability. A qualitative assessment is also provided for the Reliability Assessment and Operational Issues sections of this report, along with a new section identifying Emerging and Standing Reliability Issues. ISO-NE has identified five issues on the planning horizon that could potentially impact system reliability. ISO-NE is currently addressing these five issues under its Strategic Planning Initiative.[230]

Reliability Assessment

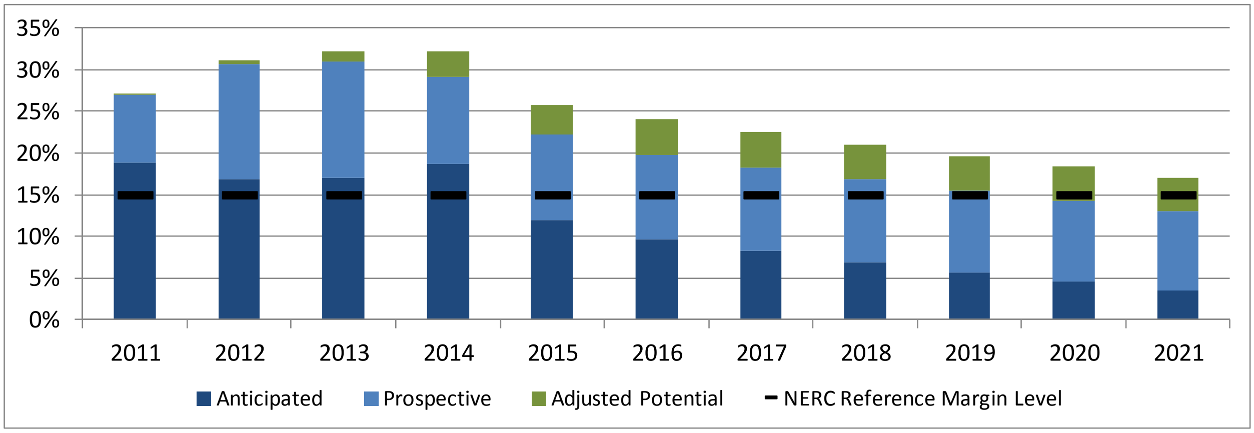
The amount of Anticipated Capacity Resources in August 2011 is 32,761 MW, which results in an Anticipated Reserve Margin of 18.9 percent of the reference demand forecast of 27,550 MW. This Reserve Margin reflects the resources (both supply & demand side) that have capacity supply obligations (CSOs) to serve the regional demand and operating reserve requirements as a result of ISO-NE's Forward Capacity Market (FCM) auctions through the 2014-2015 capacity commitment period.

The Anticipated Reserve Margin remains above the 15% NERC reference Reserve Margin through summer 2014. It was assumed that resources with CSOs for 2014-2015 will remain in place through the end of the assessment period. Without an increase in CSOs, whether through increased supply obligations of existing resources or the addition of new capacity resources, the Anticipated Reserve

[230] More information can be found on the ISO-NE web site: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

Margin declines to 11.9 percent in 2015, and continues to decrease to only 3.4 percent by 2021 (Figure 94).

Figure 94: Annual On-Peak Summer Planning Reserve Margins



New England does not have a particular capacity or Reserve Margin requirement; rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. To develop installed capacity requirements to meet the once in ten-year disconnection of Firm load resource planning reliability criterion, ISO-NE takes into account the random behavior of demand and resources in a power system, and the potential load and capacity relief obtainable through the use of various ISO-NE Operating Procedures. The capacity needs to meet this criterion are purchased through annual auctions (FCAs) three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions (ARAs) prior to the commencement year, in order to readjust installed capacity purchases and ensure that adequate capacity will be purchased to meet system needs. Therefore, ISO-NE does not expect to face any installed capacity shortages in the future.

The table (Table 81) below summarizes the 50/50 peak demand forecast, the net ICR values for the 2011-2012 through 2014-2015 capacity commitment periods, the representative net ICR values for the 2015-2016 through 2020-2021 periods, and the percentage of the resulting reserves.[231] The net ICR values for the 2011-2012 through 2014-2015 capacity commitment periods, which are calculated as the ICR minus the value of Hydro-Québec Installed Capability Credit (HQICC) for the particular capability year, reflect the latest ICR values established for those years. The ICR and HQICC values for the 2011-2012 through 2014-2015 commitment periods have been approved by FERC. The representative net ICR values for 2015-2016 and beyond were calculated by ISO-NE with stakeholder input using the following assumptions:

- The availability of 1,689 MW of total tie-line benefits from the three neighboring balancing authority areas of Québec, the Canadian Maritime provinces, and New York

[231] Resulting reserves are the amount of capacity in excess of the forecast 50/50 peak demand. Percent resulting reserves = [{(Net ICR − 50/50 peak demand) ÷ 50/50 peak demand} × 100].

- 2011 CELT Report[232] demand forecast (where applicable)
- Generating and demand-resource capability ratings, availability, and performance metrics, based on the values used to calculate the ICR for the fifth FCA for the 2014-2015 capability period

Table 81: Actual and Representative Future Net Installed Capacity Requirements/Reserve Margins[233]

Year	Forecast 50/50 Peak Demand	Net ICR and Representative Future Net ICR	Resulting Reserve Margin
	(MW)	(MW)	(%)
2011-2012	27,550	31,552	14.5%
2012-2013	28,095	31,927	13.6%
2013-2014	28,525	32,127	12.6%
2014-2015	28,970	33,200	14.6%
2015-2016	29,380	33,618	14.4%
2016-2017	29,775	34,059	14.4%
2017-2018	30,155	34,483	14.4%
2018-2019	30,525	34,887	14.3%
2019-2020	30,875	35,267	14.2%
2020-2021	31,215	35,635	14.2%

The amount of Total Internal Capacity, both supply and demand-side, which is assumed available to meet the Installed Capacity Requirement, is 34,477 MW in the 2011 summer, then increases to 36,060 MW for the 2012 summer and 36,691 MW in 2013. The Total Internal Capacity increases to a high of 36,719 MW by the 2021 summer. The amount of resources external to New England reflects Net Firm Capacity Imports of 1,136 MW in 2011, 1,531 MW in 2012, 1,646 MW in 2013, 1,751 MW in 2014 and 242 MW in 2015, and then decreases to Net Firm Capacity Exports of 5 MW by 2021. There is no reliance on emergency imports, reserve sharing or outside assistance/external resources to satisfy Net Internal Demand, other than those transactions identified above.[234]

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232 The CELT Report is ISO New England's Capacity, Energy, Loads, and Transmission Report: http://www.isone.com/trans/celt/report/index.html.

233 Table notes: (A.) Net ICR values for 2011 – 2013 are the latest values approved by the FERC (shown with 2011 CELT Load Forecast of 50-50 Peaks but calculated with 2010 CELT Load Forecast). Net ICR value for 2014 is the FERC filed ICR for 2014/15. (B.) The resulting Reserve Margin for 2011 - 2014 are based on the 2011 CELT forecast and not based on the 2010 CELT Load forecast used to determine these ICRs. (C.) Assumed Existing ICAP for 2011 through 2013 consists of the current Forward Capacity Market (FCM) obligations as of March 18, 2011. The 2013 FCM obligation is carried through and assumed to remain in place through the end of the CELT reporting period. It is assumed that the 1103 MW of Static and Dynamic De-List Bids that were cleared to leave the 2013-2014 Forward Capacity Auction will remain de-listed through the reporting period. Values decrease beyond the 2013-2014 Capacity Commitment Period because only known, long-term import contracts are reflected. (D.) The 2011 CELT resources includes generating capability based on Seasonal Claimed Capability (SCC) values and includes all existing and projected ISO New England generating assets. Future generating assets consist of non-FCM resources that are expected to go commercial in 2011 or 2012, and all new resources with FCM CSOs. The capabilities of the FCM resources are based on their Qualified Capacity. Also includes DR CSO as reflected in the 2011 CELT.

234 In the determination of the ICR, ISO-NE does include approximately 1,665 MW – 1,800 MW of "Tie-Benefits" from neighboring systems, to deliver emergency or outside assistance, in the event of a capacity deficiency.

The New England subregion of NPCC does not treat short-term (1-5 years) and long-term (6-10 years) Reserve Margin requirements differently, although more attention is paid to the short-term Reserve Margins due to their applicability in forecasting resource adequacy requirements.

ISO-NE does not specifically track the smaller generators located on the distribution system. Behind-the-meter generation basically is unknown to ISO-NE operations for dispatch purposes, but any distributed generation that does make it onto the grid gets financial reimbursement through the ISO-NE Settlement-Only process within the ISO-NE Markets. A form of distributed generation called Real-Time Emergency Generation (RTEG), which is defined as "Active DR," is defined at the dispatch zone, is operated based on real-time system conditions via dispatch by ISO-NE, and reduces energy demand during "reliability" hours.

Gas-fired capacity amounts to 13,631 MW, or 42.5% of New England's total 2011 summer generation capacity of 32,037. Due to the major contribution to overall capacity from gas-fired capacity, fuel supply disruptions to regional gas-fired generation can impact resource adequacy.[235] However, because the majority of these facilities are direct-connect customers of five large, regional interstate gas pipelines, the simultaneous loss of gas supply or downstream-transmission to all these five interstate pipelines is improbable. In general, the low priority nature of regional gas-fired generators' fuel supply and transportation entitlements can create temporary operable capacity problems, primarily during winter, when most of the regional pipelines are fully subscribed and flowing natural gas to Firm customers of the regional gas LDCs.

Due to the contribution to overall capacity from oil-fired facilities (7,112 MW at 22.2 percent), fuel supply disruptions to regional oil-fired facilities (some of which are dual-fuel capable) could impact resource adequacy, although on-site oil storage inventories at these facilities are usually in the 5-15 day supply range. It is assumed that most dual-fuel units would swap over to their unconstrained fuel supply. Therefore, temporary fuel supply disruptions to oil-fired facilities should not be problematic.

Due to the minor contribution to overall capacity from coal facilities (2,664 MW at 8.3 percent), fuel supply disruptions to regional coal facilities would have a minor impact on resource adequacy. On-site coal inventories are usually in the 15-30 day supply range. Therefore, temporary fuel supply disruptions at coal facilities should not be problematic.

Due to the relatively small contribution to overall capacity from hydro-electric facilities (1,341 MW at 4.2 percent), regional drought conditions could reduce hydro-electric energy production. This could, however, be readily supplemented by increased levels of other types of fossil-based generation.

The New England area is currently not experiencing a drought. However, in the event that the region was experiencing an extended drought, some traditional hydro-electric stations could be temporarily

[235] All fuel type amounts and percentages are based on each generator's reported primary fuel type.

capacity or energy constrained. Other fossil stations could also be temporarily capacity limited due to lack of cooling water or other (heat-related) environmental issues.

ISO-NE's Operating Procedure No. 21 – *Action during an Energy Emergency* (OP 21)[236] addresses energy emergencies, which may occur as a result of sustained national or regional shortages in fuel availability or deliverability to New England's generation resources. Because fuel shortages may impact the subregion's ability to fully meet system demand and operating reserves 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 subregion to minimize the loss of operable generating capability due to fuel shortages. OP 21 can be implemented to mitigate most types of fuel shortages impacting the electric sector, no matter what the triggering event may have been. In addition, ISO -NE does not consider any Energy-Only, Existing-Uncertain wind or transmission-limited resources in its resource adequacy assessment.

Renewable Portfolio Standards (RPS) are state legislated targets for a renewable resource portion in the wholesale energy mix, generally applicable to competitive retail electric suppliers. These suppliers need to obtain a specific percentage of their energy from renewable resources or pay an Alternative Compliance Payment (ACP) for any deficiency. The ACP serves as a price cap and can also be used to fund new renewable projects.

The retail suppliers affected implement the RPS by acquiring Renewable Energy Credits (RECs) from renewable resources that reside both inside and outside the subregion. The revenues received from selling these RECs can create financial incentives to build renewable resources. The RPS target usually grows each year and is broken down by specific "Classes" for existing and new resources and, in some states, special technology categories. The "new" classes of RPS typically have an increasing percentage that must be supplied from renewable resources for a state's supply mix goals. Some states also have related goals for Energy Efficiency, which could then reduce the need for supply-side RPS resources. Increases in renewable resources leads to increased fuel diversity, which can have a positive impact on system reliability. The New England States' RPS Classes and Energy Efficiency for the target year 2020 are shown below (Table 82)

[236] OP 21 is located on the ISO-NE web site: http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.

Table 82: NPCC State Renewable Portfolio Standards (RPS)[237]

State	Capacity Classes	RPS Target by 2020 (%)
Maine	Existing	30%
	New	10% of Capacity by 2017
New Hampshire	I New	11%
	II Solar	0.30%
	III Existing Biomass	6.50%
	IV Existing Small Hydro	1.00%
Massachusetts	New	15%
	Existing I & II	3.6% & 3.5%
	EE	All new Energy Growth
Rhode Island	Existing	2%
	New	14%
Connecticut	I New	20%
	II Existing	3%
	III CHP and EE	4%
Vermont	{Has no formal RPS}	20% Goal by 2017
	SPEED Program	All Energy Growth Above 2005

Variable resources are treated as any other resource in ISO-NE's resource adequacy assessment, in that they are expected to provide their CSO. Their CSO cannot exceed their Qualified Capacity, which is based on historical generation during on-peak hours for existing resources, or on engineering data for new resources.

ISO-NE has instituted several processes to aid in the integration of variable resources into ISO planning and operations. ISO-NE has concluded a study for the New England Governors that provides a transmission planning service focused on the integration of renewable and carbon-free energy resources into New England's power grid. ISO-NE also assists the New England states in coordination with the subregion's Transmission Owners in the development of a long-term plan for the New England transmission system that incorporates the unique attributes and goals of each state and the possibility of additional renewable or carbon-free electricity imports from neighboring regions. ISO-NE also provides performance and impact evaluations on various transmission and generation scenarios from both a reliability and economic perspective.

ISO-NE has finalized a Wind Integration Study that focuses on what is needed to effectively plan for and integrate wind resources into system and market operations. The main part of the study focused on developing a mesoscale and wind plant model for the New England area, including onshore and offshore capability. Using these models, the study looked at several wind development scenarios to determine their impact on unit commitment practices, scheduling, automatic generation control, reserves, market operations and rules as well as other key elements of the system. Another important component of the study was to develop technical requirements for new wind resources interconnecting to the system, including the provision for data collection to develop a state of the art wind forecasting tool to use in system and market operations.

[237] EE – Energy Efficiency, CHP – Combined Heat & Power, SPEED – Sustainably Priced Energy Enterprise Development System.

Within ISO-NE's FCM, qualifying Demand Response (DR) (including Energy Efficiency) is treated as supply-side capacity. Within FCM, Demand Response resources are installed measures that result in additional and verifiable reductions in end-use electricity demand. These verifiable reductions serve to reduce the peak demand on the system and maintain operating reserves, avoiding the dispatch of additional generation. Demand Response can displace demand permanently, over pre-defined hours or in real-time when dispatched by the ISO-NE. The minimum size of Demand Response in FCM is 100 kW. ISO-NE's FCM DR resources can be made up of smaller DR assets (< 100 kW), which can then be aggregated into a demand-side portfolio of FCM resources of size 100 kW and above.

Within ISO-NE's FCM, Demand Response is separated into two (2) categories:

1. Passive Demand Response: Includes both On-Peak & Seasonal Peak components. This Passive Demand Response is defined at the load zone level, is non-dispatchable, and should reduce energy demand during peak hours.
2. Active Demand Response: Includes both Real-Time Demand Response (RTDR) & Real-Time Emergency Generation (RTEG) components. Active Demand Response is defined at the dispatch zone, is operated based on real-time system conditions via dispatch by ISO-NE, and reduces energy demand during "reliability" hours.

Passive Demand Response primarily consists of Energy Efficiency (EE). EE resources in the FCM are treated as supply-side capacity that can contribute to meeting the subregion's ICR. ISO-NE's demand forecast also reflects the contribution of non-FCM EE and Federal appliance efficiency standards. However, at this time, estimates of State EE Program are not used to reduce the ICR or demand forecast. ISO-NE and regional Stakeholders are currently in discussion concerning this and other related issues.

The only significant retirement of capacity in New England is the submittal of a non-price retirement[238] for the entire Salem Harbor station, currently rated at approximately 745 MW. Salem Harbor has three coal-fired units at a combined rating of 308 MW and one oil-fired unit rated at 437 MW. Salem Harbor units 1 & 2 (158 MW) are scheduled to retire by the end of 2011. Salem Harbor 3 & 4 (587 MW) are scheduled to retire by June 1, 2014. ISO-NE and regional Transmission Owners have been studying this retirement. To ensure the continued reliability of the electric system within northeastern Massachusetts, transmission enhancements are under investigation for expedited installation.[239] Resource flexibility and performance, increased reliance on natural gas-fired capacity, the retirement of fossil-fueled generators, the integration of a greater level of variable resources, and the potential for non-transmission alternatives to address system reliability needs are the five major concerns facing New England at this time.

[238] A non-price retirement is a binding request to retire the entire capacity of a Generating Capacity Resource. Upon retirement, the interconnection rights for the unit are terminated.

[239] For more information on the retirement of Salem Harbor, reference: http://www.iso-ne.com/pubs/spcl_rpts/2011/salem_harbor_npr_summary_05102011.pdf.

At this time, there are no plans to install more Under Voltage Load Shedding (UVLS) in New England. Currently, northern New England has the potential to arm approximately 600 MW of load shedding as part of UVLS. However, it is important to recognize 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 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 Project and the Maine Power Reliability Program (MPRP). The Vermont Southern Loop Project was completed in late 2010 and the MPRP project is scheduled to be completed in 2014.

There are no special protections system schemes (SPS) that are proposed to be installed in lieu of proposed regulated transmission facilities to address system reliability needs in New England in assessment timeframe. However, a new, temporary SPS was recently installed in Southern Maine as part of the MPRP. This SPS is needed to ensure reliable system operation due to configuration changes at South Gorham, while the MPRP is under construction. Once construction of the necessary portions of the MPRP is complete, anticipated in 2014, this SPS will be removed.

ISO-NE's Regional System Plans (RSPs) identify the region's needed transmission improvements over a ten-year period. The current plan builds on the results of previous RSPs and other regional activities. The transmission projects have been developed to coordinate major power transfers across the system, improve service to demand, and meet transfer requirements with neighboring balancing authority areas.

Transmission plans continue to be developed to serve demand growth throughout the New England subregion. This includes service to demand areas in Maine, New Hampshire, Vermont, Western Massachusetts, Southeastern Massachusetts, Northeastern Massachusetts, Greater Rhode Island and Connecticut (see Transmission section). Future resources are included in reliability assessments only if they have received an obligation through the FCM, are contractually bound by a state-sponsored RFP, or have a financially binding obligation pursuant to a contract. However, assessments still consider reasonable planned and unplanned outages of the future resources in the same manner as existing resources.

There are no known existing reactive power-limited areas within New England's transmission system. The studies described above have documented the upcoming reactive power needs of the system. Transmission planning studies have ensured that adequate reactive resources are provided throughout New England. In instances where dynamic reactive power supplies are needed, devices such as STATCOMs, SVC's, Synchronous Condensers, and DVARs have been employed to meet the required need. If additional reactive power support is necessary in real-time, supplemental generation commitment has been employed to meet the required need. Additionally, the system is reviewed in the near-term via operating studies to develop operating guides to confirm adequate voltage/reactive performance. In creating transfer limits based on the dynamic performance of the system, New England applies a 100 MW margin to transfer limits.

New England has a number of installations of new technologies. These include STATCOMs, voltage source converter based HVdc, variable reactors, a short section of gas-insulated transmission line (GITL), synchronous condensers, and D-VAR. These types of technologies are always under consideration as tools to address future system concerns.

As noted earlier, the uncertainty and variability of wind and solar resources may pose operational challenges. The New England Wind Integration Study (NEWIS) investigated the operational impacts of different penetration levels of wind resources. The study recommended changes in operating practices and procedures to accommodate a large-scale penetration of wind resources.

ISO-NE routinely reviews the existing, pending, and promulgating environmental regulations for their potential impacts on existing or future capacity. Under the workloads associated with its Strategic Planning Initiative, ISO-NE has identified several regional power stations that may be retired due to the economics of compliance with pending state and federal air and water regulations. Currently, the procedures that are in place to maintain system reliability include reliability agreements and out-of-merit unit commitment. However, ISO-NE is studying longer-term solutions to the problem, such as appropriate enhancements to wholesale market design and system planning procedures.

Emerging environmental regulations will very likely require large capital investments that are uneconomic for many older fossil-fueled resources. While the exact form and timing of the requirements remain uncertain, there is a very high likelihood that substantial compliance investments will be required by owners of existing New England resources to continue operations. This could lead to a significant quantity of older generation choosing to retire rather than comply.

Losing a significant quantity of coal, oil and nuclear capacity could further increase the subregion's dependence on natural gas-fired resources. If all of the subregion's older oil units were to seek retirement, new capacity resources would be required to satisfy the Installed Capacity Requirement.

ISO-NE has initiated and is aggressively promoting a regional dialogue focused on solutions that can avert undesirable outcomes. ISO-NE has initiated a study to better quantify the implications of this issue. This analysis will complement the 2010 economic planning studies. For more information, reference the *Emerging and Standing Reliability Issues* section.

There are no project slow-downs, deferrals, or cancellations that may impact reliability in New England.

Demand

A continuation of the economic downturn has again lowered this year's forecast for summer peak demand and energy use when compared to last year's forecast. The projected 2011 summer peak demand forecast is 27,550 MW. This year's forecast of the 10-year (2011-2021) 50/50 summer peak demand compound annual growth rate (CAGR) is 1.24 percent, slightly lower than 2010 projections (Table 83). The key factor leading to the lower summer peak demand forecast is that the economic downturn has significantly impacted the actual summer peak and energy demand within the New

England subregion, which results in approximately a one year delay in achieving the same demand levels that had been previously predicted.

Table 83: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	27,550	31,559	4,009	1.24%	14.6%
Net Internal	25,515	28,160	2,645	0.90%	10.4%

The projected 2011 winter peak demand forecast is 22,255 MW. This year's forecast of the 10-year winter peak demand CAGR is 0.5 percent, which is the same as last year's. The forecast for winter peak demand is slightly higher (by 170 MW) than last year's forecast by the end of the forecast period based on updated historical demands and economic and price of electricity forecasts. The winter peak is less weather sensitive than the summer peak, closely linked to residential demand (the convergence of darkness and dinner), and less impacted by the recession.[240]

This year's forecast of the 10-year net annual energy CAGR is 1.1 percent, which has increased from last year's forecast of 0.9 percent. However, the overall forecast for net annual energy use is again lower than last year's forecast due to the economic downturn.

ISO-NE's reference case demand forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted temperature-humidity index (WTHI) of 79.88, which is equivalent to a dry-bulb temperature of 90.2 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The reference case demand forecast is based on the most recent reference economic forecast, which reflects the economic conditions that "most likely" would occur.

ISO-NE develops an independent demand forecast for the Balancing Authority area as a whole and the six states within it. ISO-NE uses historical hourly demand data from individual member utilities, which is based upon Revenue Quality Metering (RQM), to develop historical demand data which the regional peak demand and energy forecasts are based upon.[241] From this historical data, ISO-NE develops a forecast of both monthly peak and energy demands by state. The peak demand forecast for the subregion and the states can be considered a coincident peak demand forecast.

Demand-side resources are considered capacity resources in New England's FCM. Under FCM, there are passive and active demand resources. The active demand resources can be triggered by ISO-NE in real-time under ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP 4) to help mitigate a capacity deficiency, or dispatched day-ahead to mitigate a projected capacity deficiency.

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[240] The winter peak is also somewhat-dependent on electric heating demand, while the summer peak is directly-dependant on air conditioning demand. A much larger number of homes in New England have air conditioning versus electric heat.

[241] RQM is submitted to the ISO-NE Settlements Department.

As part of the qualification process to participate in a Forward Capacity Auction, any new demand resource must submit detailed information about the project, including location, project description, estimated demand reduction values, and projected commercial operation dates along with a project completion schedule. In addition, new demand resources must submit a Measurement and Verification (M&V) Plan, which must be approved by ISO-NE. The project sponsor is required to submit certification that the project complies with their ISO-approved M&V Plan. ISO-NE has the right to audit the records, data, and actual installations to ensure that the Energy Efficiency projects are providing the demand reduction as contracted. ISO-NE tracks the project against their submitted schedules, thereby taking a proactive role in monitoring the progress of these resources to ensure they are ready to reduce demand by the start of the applicable FCM commitment period.

The demand resources that have won the bids that entitle them to supply capacity to the New England capacity market through the first four forward capacity market auctions are: 1,824 MW of demand resources (560 MW of passive and 1,264 MW of active) available in July 2010, 2,035 MW by 2011 summer (774 passive, 1,261 active), 2,606 MW in 2012 summer (960 passive, 1,646 active), 3,003 MW in 2013 summer (1,148 MW passive, 1,855 MW active), and 3,399 MW in 2014 summer (1,398 MW passive, 2,001 MW active), which are then held constant through the 2021 summer (Table 84).

Table 84: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**-**	**-**	**-**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	-	-	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	2,035	3,399	1,364
Total Dispatchable, Controllable Demand Response	**2,035**	**3,399**	**1,364**
Total Demand-Side Management	**2,035**	**3,399**	**1,364**

In addition to reliability-based DR programs, ISO-NE administers a price-response DR program where demand voluntarily interrupts based on the price of energy. As of May 2011, there were approximately 61 MW enrolled in the price response program. These programs are not counted as capacity resources since their interruption is voluntary.

Although several types of demand-side management resources can be used to satisfy state-mandated, renewable portfolio standards (RPS), ISO-NE does not require that information be submitted in order to participate in applicable demand-side markets.

ISO-NE addresses peak demand uncertainty in two ways:

- Weather: Annual peak demand distribution forecasts are made based on 40 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded).[242]
- Economics: Alternative forecasts are made using high and low economic scenarios.

ISO-NE also reviews projected summer and winter conditions of the assessment period using the annual extreme, 90/10 peak demand based on the reference economic forecast.

Generation

The New England subregion expects to have the following aggregate capacity available on-peak through 2021 (Figure 95). Capacity additions consist primarily of gas and renewable resources (Figure 96). Capacity in the categories of *Existing-* (*Certain*, *Other* and *Inoperable*), *Future-* (*Planned* and *Other*) and *Conceptual* are projected to serve demand during this long-term assessment period.

Figure 95: On-Peak Capacity Mix by Fuel Type

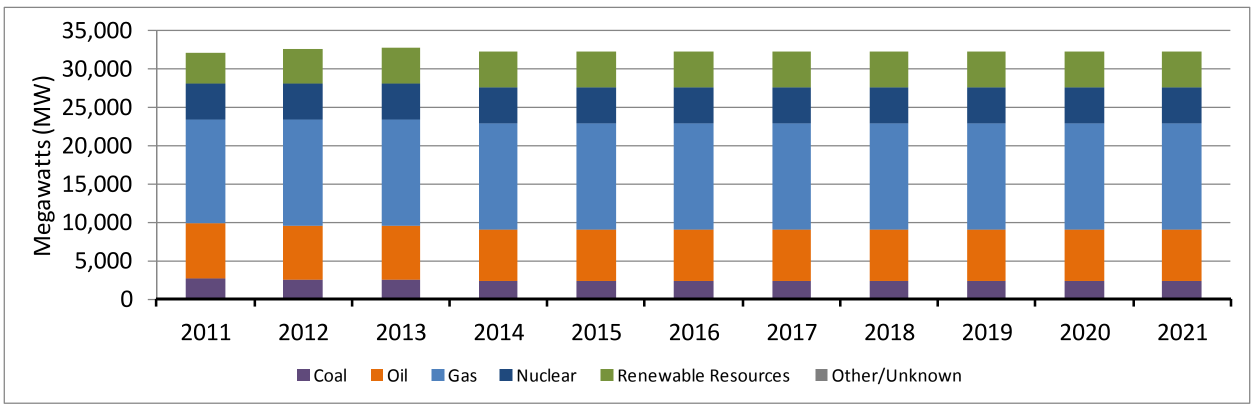
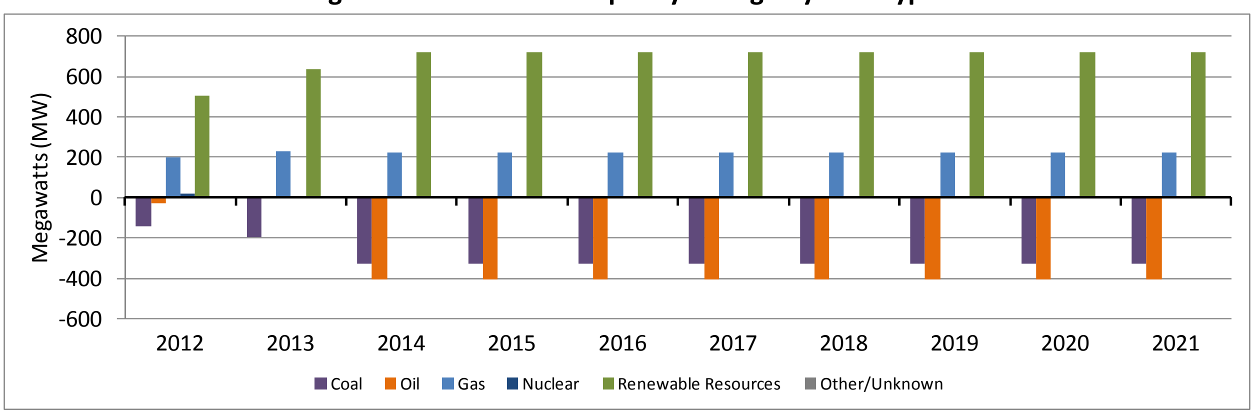


Figure 96: Annual Net Capacity Change by Fuel Type



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

Under FCM, regional capacity that has a capacity supply obligation (CSO) is reported within this assessment as *Existing-Certain* capacity and all remaining non-CSO capacity is reported as *Existing-Other* capacity. Since ISO-NE has already procured the CSO for the 2014-2015 Capability Period, regional generating capacity through that time period is identified within one of these two categories. Beginning with the 2015 summer, those prior CSOs are then held constant throughout the assessment period.

For August 2011, ISO-NE reports 34,477 MW of capacity, which includes 29,590 MW of *Existing-Certain* capacity, 2,227 MW of *Existing-Other* capacity, 625 MW of capacity derates,[243] 2,035 MW of Demand Side Management (DSM) resources, and 0 MW of *Existing-Inoperable* capacity.

For August 2011, ISO-NE reports 116 MW of nameplate wind capacity, which includes 26 MW of *Existing-Certain* wind capacity expected on-peak along with a 90 MW on-peak derate of *Existing-Other* wind capacity (Table 85). By August 2021, ISO-NE reports an additional 495 MW of *Future-Planned* nameplate wind capacity with 100 MW expected on-peak along with a 395 MW on-peak derating. Planned wind capacity is rated differently from its nameplate capability due to Market Rules for rating intermittent supply-side resources, which also takes into account the site-specific wind characteristics of those projects. In 2021, *Conceptual* wind capacity is 2,525 MW, which is based on nameplate ratings, and has target in-service dates of 2012 through 2016.

Table 85: Summer Renewable Resources On-Peak

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	26	169	143
	Derated	90	557	467
	Wind - Total Nameplate Capacity	**116**	**726**	**610**
Solar	Expected	0	1	1
	Derated	0	2	2
	Solar - Total Nameplate Capacity	**0**	**4**	**3**
Hydro	Expected	1,349	1,416	67
	Derated	467	467	0
	Hydro - Total Nameplate Capacity	**1,816**	**1,883**	**67**
Biomass	Expected	902	1,025	123
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**902**	**1,025**	**123**

For August 2011, ISO-NE reports 147 MW of *Conceptual* capacity on the system which includes 7 MW of hydro resources. However, by August of 2021, ISO-NE reports an additional 6,428 MW of *Conceptual* capacity potentially on the system. This amount also includes on-peak *Conceptual* capacities of 2,525 MW of wind, 0 MW of solar, 33 MW of hydro-electric, and 357 MW of biomass. The on-peak capacity

[243] Derates for all resources other than wind and hydro are based on the difference between their CSO and either their Seasonal Claimed Capability (SCC) or their Qualified Capacity, which is the maximum amount with which they could participate in the FCAs. Qualified Capacity and SCC are similar to each other. For wind and hydro, derates are the difference between the SCC and nameplate capacity.

ratings of variable or intermittent resources are determined from the Market Rules pertaining to qualification determination of capacity within the FCM.

ISO-NE's Reserve Margin calculations include Future Capacity Additions that are projected to begin commercial operation by the end of each year. If the new project's in-service date is prior to August 1st of that year that capacity is included within the *Future-Planned* capacity for the summer of the year, otherwise it is included within the *Future-Planned* capacity for the winter of the following year. This information is based on either the date specified in a signed Interconnection Agreement (IA) or discussions with ISO-NE indicating that the project is nearing completion and is preparing to become an ISO generator asset. Also included in the *Future-Planned* capacity additions are new projects that have contractual obligations within the ISO-NE FCM for the years 2011-2014. *Conceptual* capacity is subsequently identified as all the capacity remaining within the ISO-NE Generation Interconnection Queue that has not been designated as *Future-Planned* capacity, through the selection process identified above.

ISO-NE has a total of 7,992 MW of projects categorized as either *Future-Planned* capacity or *Conceptual* capacity within its Generator Interconnection Queue, with in-service dates ranging from 2011 to 2014.[244] Although some projects that reside within the ISO-NE Generator Interconnection Queue have declared in-service dates of 2011 or 2012, some of those projects have not demonstrated viable pre-commercial activities and have therefore been categorized as *Conceptual* capacity. The Queue projects were included in the *Future-Planned* category if they had an FCM obligation or were projected to be in service by 2011 summer. All other Queue projects were treated as *Conceptual*.

A 20 percent Confidence Factor has been applied to the amount of projected *Conceptual* capacity resources. This 20 percent Confidence Factor represents the amount of *Conceptual* capacity that may become commercialized within the subregion, starting in winter 2011-2012. This 20 percent Confidence Factor is held constant going forward in time. In the 2021 summer, the total amount of *Conceptual* capacity resources is 6,428 MW and applying the 20 percent Confidence Factor equates to approximately 1,286 MW.

ISO-NE currently addresses generation deliverability through a combination of transmission reliability and resource adequacy analyses. Detailed transmission reliability analyses of sub-areas of the New England 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. New capacity resources are subject to overlapping impact studies to ensure deliverability within the sub-area (load zone) in which they are seeking to interconnect. These load flow studies are part of the FCM's new capacity resource qualification process. The ongoing transmission planning efforts associated with the New England Regional System Plan (RSP) support compliance with the NERC Transmission Planning requirements and assure that the transmission system is planned to sufficiently integrate generation with demand.

[244] As of the April 1, 2011 ISO-NE Generation Interconnection Queue publication.

As noted earlier, ISO-NE does not specifically track the smaller generators located on the distribution system. Behind-the-meter generation basically is unknown to ISO-NE operations for dispatch purposes, but any distributed generation that does make it onto the grid gets financial reimbursement through the ISO-NE Settlement-Only process within the ISO-NE Markets. A form of distributed generation called Real-Time Emergency Generation (RTEG), which is defined as "Active DR," is defined at the dispatch zone, is operated based on real-time system conditions via dispatch by ISO-NE, and reduces energy demand during "reliability" hours.

Capacity Transactions

The companies within the New England subregion of NPCC expect to have the following aggregate Firm capacity imports and exports during the long-term assessment period (Table 86).

Table 86: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	1,236	95	505	97
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**1,236**	**95**	**505**	**97**
Exports	Firm	100	100	100	100
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**100**	**100**	**100**	**100**
	Net Transactions	**1,136**	**(5)**	**405**	**(3)**

Firm summer capacity imports amount to approximately 1,236 MW in 2011, 1,631 MW in 2012, 1,746 MW for 2013, 1,851 MW in 2014 and 342 MW 2015. The capacity imports for 2011 through 2014 reflect the results of the appropriate FCAs. Since the FCA imports are based on one-year contracts, beginning in 2015 the imports reflect only known, long-term ICAP contracts. Firm summer capacity imports are 120 MW in 2016 and then level off at 95 MW for the 2017 through 2021 summers. If the imports that cleared in the 2014 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or demand-side resources. There are no Expected or Provisional capacity imports projected for the assessment period.

The entire amount of ICAP imports is backed by Firm contracts for generation and the imports under the FCM are import capacity resources with an obligation for the 2011-2014 commitment periods. Although there is no requirement for those imports to have Firm transmission service, it is specified that deliverability of Firm imports must meet New England delivery requirements and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of Firm energy, but the market participant bears the associated risk of market penalties if it chooses to use non-Firm transmission services. Import assumptions are not based on partial path reservations.

For the 2011 summer, ISO-NE reports a Firm Capacity Sale to New York (Long Island) of 100 MW, anticipated to be delivered via the Cross-Sound Cable (CSC). This Firm capacity sale is held constant through the assessment period. It should be noted that there is no Firm transmission arrangement through the New England Pool Transmission Facilities system associated with this contract. There are no Expected or Provisional Capacity Exports projected for the assessment period. Export assumptions are not based on partial path reservations.

Transmission

ISO New England has identified projects[245] that address transmission system performance issues, either individually or in combination. Some of the projects, as described below, address local reliability issues and also have the ancillary benefit of improving the performance of major transmission corridors and thus the overall performance of the system.

Maine

The Maine Power Reliability Program (MPRP) analyses have identified the potential difficulties in moving power into and through Maine to various load pockets spread throughout the state under stressed conditions. The existing system is highly dependent upon the 345 kV lines, which consist of only a single 345 kV path in the north and two parallel 345 kV paths in the south. Furthermore, there are a limited number of 345/115 kV autotransformers to supply the 115 kV network. System studies have shown that loss of a single 345 kV transmission line or autotransformer can yield unacceptable results, which are further exacerbated when a second contingency is contemplated. The largest of these pockets is the area in southern Maine along the seacoast, which includes the Portland area. An area in Maine, often referred to as western Maine, is also challenged to supply area demand, which includes a number of large paper mills, especially when these demands are modeled at their contractual limits. Additionally, there are a number of SPS which have become a significant concern in real-time operations and have also been shown to become inadequate in the future. The MPRP effort proposes numerous system additions to address these concerns. At a high level, these upgrades will create a new 345 kV path, extending from the Orrington substation in central Maine to the Three Rivers switching station located in southern Maine. This project also adds a number of 345/115 kV autotransformers and creates a new 115 kV path into western Maine. Until the MPRP is placed in service, which is anticipated to occur in 2014, system operators will rely heavily on available resources and SPS in the area to ensure the reliability of the system.

New Hampshire

A 10-year study of the New Hampshire area has initially identified the potential for system concerns throughout much of the state for numerous different contingencies and resource outages. The more significant concerns are related to serving the southern and seacoast areas, which are served from a limited number of autotransformers and insufficient 115 kV networks. Further concerns are related to moving power into central New Hampshire, which is served through a 115 kV path and serving northern New Hampshire following the loss of the single 230/115 kV autotransformer at Littleton, NH. These

[245] Please see project list in the attached data.

concerns are addressed through the planned addition of new autotransformers in the seacoast, southern and northern areas, coupled with new transmission. The exact configuration of the new transmission is under review.

Vermont

A 10-year study of the Vermont area has identified the potential for system concerns moving power through the state for various future contingencies. Due to limited generation supplies and a significant demand concentration in the northern part of the state, power must be imported over significant distances to serve this area. Therefore, when either a southern 345 kV line or a key 345/115 kV autotransformer in the state is lost, the next critical contingency would result in numerous reliability concerns in Vermont, as well as electrical facilities in neighboring states. Solutions to these concerns include providing additional reactive support, adding new autotransformers, reconductoring a number of 115 kV lines, or adding a new 230/345 kV circuit into Vermont.

Connecticut

The original New England East - West Solution (NEEWS) studies included the evaluation of both the ability of the system to move power from East to West across southern New England and the ability to move power into and across Connecticut. Past analyses had indicated that Connecticut would need either transmission improvements or over 1,500 MW of supply or demand-side resources by 2016. Past studies also showed that Connecticut had internal transmission elements that limited east–west power transfers across the central part of the state. The movement of power from east to west in conjunction with higher import levels to serve Connecticut had resulted in overloads of transmission facilities located within the state.

Updated transmission assessments have shown that resources planned and obligated by contract for Connecticut are sufficient to meet reliability requirements until about 2015, assuming no supply-side resource retirements. With the addition of significant resources in the west, a more immediate need now exists for an improvement in the west to east transfer capability, as opposed to the original east to west need. In the absence of additional resources, the proposed solution involves new interstate 345 kV transmission lines from western Massachusetts into Connecticut and from central Massachusetts into Rhode Island and then into eastern Connecticut.

Southwest Connecticut

Issues identified within the long-term reliability Needs Assessment for the area of southwest Connecticut consist of thermal overloads and low voltage violations. Alternatives to address these concerns and deficiencies are under study.

Massachusetts – Boston Area

A long-term reliability Needs Assessment has been completed for the Greater Boston area.
Various transmission contingencies result in overloads of transmission facilities and low voltages within the area. Alternatives under consideration consist of a mix of new 345 kV and 230 kV transmission lines as well as 345/230 kV and 230/115 kV transformation. Preliminary solutions to address concerns in the northern and southern portions of Boston have been presented to the stakeholders and solutions for

the central area are currently under study. Complete solution development is currently planned to be finished by the end of 2011. Some portions of the solutions are being expedited to address near-term reliability concerns.

Massachusetts – Berkshire County/Pittsfield Area

A Needs Assessment has identified needs for the Berkshire County/Pittsfield area within western Massachusetts. Under certain system conditions, the study identified overloads on various 115 kV transmission lines and the 345/115 kV autotransformer at Berkshire. Low voltage violations were observed at several substations in the area. Possible solutions to these issues include adding 345/115 kV autotransformers, upgrading long segments of old 115 kV transmission lines, and installing additional capacitors to mitigate both thermal and voltage concerns. The preferred transmission solution has been finalized, with the in-service date for the transmission upgrades targeted for 2014.

Massachusetts – Springfield (MA)

The NEEWS studies, resulting in part in the Greater Springfield Reliability upgrades, have found that local double-circuit tower outages, stuck-breaker outages, and single-element outages result in severe thermal overloads and low voltage conditions. These overloads are exacerbated when Connecticut transfers increase, especially with a major 345 kV line out of service. The proposed solution eliminates a number of multi-circuit towers in the area and installs a new 345 kV line between Ludlow, Massachusetts and north-central Connecticut. These upgrades are under construction with a targeted in-service date of 2014.

Rhode Island

The Greater Rhode Island studies, in conjunction with the NEEWS studies, have identified significant thermal constraints on the 115 kV system. The outage of any one of a number of 345 kV transmission lines results in limits to power transfer capability into Rhode Island. With a line out of service, the next critical contingency would result in numerous thermal and voltage violations, and possibly the shedding of over 500 MW of demand. This could be resolved by transformer additions, a new 345 kV line between West Farnum and Kent County, and the additional central Massachusetts to Connecticut 345 kV line (mentioned above) being looped into the West Farnum substation.

Presently there are no significant concerns over meeting target in-service dates of the transmission projects. However, if the implementation of these projects is delayed, interim measures will be taken, such as issuing gap Requests-for-Proposals (RFPs) to install temporary generation in a specific area of the system.

Currently, there are no transmission constraints which prevent the system from being operated in a manner which ensures the reliability of the New England-wide system. The proposed projects with the target in-service dates are expected to enhance the long-term reliability of the New England bulk power supply system.

No additional significant substation equipment such as SVC, FACTS controllers or HVDC is currently planned to be added to the system.

Operational Issues

There are no existing or potential systemic generating unit or transmission outages that are anticipated to impact reliability during the next 10-years. The system will remain reliant on a number of Special Protection Systems and local operating procedures until transmission solutions are placed in service in a number of areas within New England. As noted earlier, resource flexibility and performance, increased reliance on natural gas-fired capacity, the retirement of fossil-fueled generators, the integration of a greater level of variable resources, and the potential for non-transmission alternatives to address system reliability needs are the five major concerns facing New England at this time.

If New England experiences extreme summer weather that results in 90/10 peak demands or greater, ISO-NE still should have enough operable capacity available to reliably manage the bulk power system. However, if supply-side outages diminish New England's operable capacity to serve these 90/10 peak demands, ISO-NE will need to invoke Operating Procedure No. 4 - *Action During a Capacity Deficiency* (OP 4). OP 4 is designed to provide additional generation and load relief needed to balance electric supply and demand while striving to maintain appropriate levels of operating reserves. Load relief available under OP 4 includes relief from voltage reduction and emergency assistance from neighboring balancing authorities.[246]

During extremely hot summer days or combined with low hydrological conditions, there may be environmental restrictions on river-based or coastal generating units due to environmental constraints. Such conditions could result in temporary operable capacity reductions ranging from 100 to 500 MW. These reductions are reflected in ISO-NE's forced outage assumptions. ISO-NE monitors these situations and projects adequate resources to cover such environmental outages or reductions.

As of the 2011 summer, there is only 26 MW of *Existing-Certain* on-peak wind capacity on the New England system, so operational challenges from the integration of variable resources are negligible at this time. However, in the near-term, one emerging issue is the potential for a large influx of these new, intermittent wind resources to be commercialized within the subregion. Concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the potential build-out of these new supply-side resources. Because of this and other operational concerns, ISO-NE has finalized a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid.

Due to the fact that distributed generation must be integrated into the local electric company's distribution systems, it must comply with the interconnection standards applicable to such systems. This distributed generation is traditionally not a major concern for bulk power system operation, although relatively large DG projects can be studied by ISO-NE. ISO-NE does not anticipate any

[246] Within NPCC, there are power systems that are both summer and winter peaking. Since the New England system is summer peaking, surplus operable capacity should be available with the NPCC Canadian systems due to their winter peaking nature. This surplus operable capacity could be delivered to New England in the event OP 4 is required. Routine discussions within NPCC identify whether surplus operable capacity is available on a daily, weekly or seasonal basis.

operational problems or reliability concerns resulting from the levels of distributed generation enrolled within the demand response programs.[247] The FCM qualification process requires additional information for projects that include the use of DG to ensure that they comply with the definition of DG within FCM. A 600 MW cap on real-time emergency generation (RTEG) within FCM was a limit that was negotiated during the development of the Market Rules for FCM and this amount is not expected to change within the near future. [248] In August 2010, 688 MW of RTEG cleared the fourth FCA for the 2013 - 2014 Capacity Commitment period. This amount was subsequently pro-rated down to the 600 MW RTEG limit for inclusion within ICR modeling.

As discussed earlier, the 2,035 MW of demand resources, which consist of Energy Efficiency and distributed generation, are all treated as capacity resources. Demand resources will represent 6.2 percent of the representative capacity resources needed within the New England electric system in 2011.[249] There are currently no reliability concerns projected as a result of these amounts of demand response penetration into the system.

New England relies upon the facility owners to investigate relay protection misoperations. The facility owners will then determine the cause of the misoperation and implement corrective actions for that facility and other facilities which may also have the same concern. New England has a number of forums which allow the equipment owners to share information which they feel may be useful to other equipment owners in preventing similar events.

As an NPCC subregion, ISO-NE is bound to comply with NPCC's *Regional Reliability Reference Directory # 1 - Design and Operation of the Bulk power system.*[250] Within this Reliability Reference (document), NPCC mandates that ISO-NE perform annual assessments of potential contingencies or topologies that could impact bulk power system operation. One subset of this analysis is the *"Extreme System Conditions Assessment"* which dictates that ISO-NE transmission planners assess several types of *"low probability"* events or scenarios in order to understand potential outcomes.[251] These types of assessments are based on transmission analysis. The NPCC *Regional Reliability Reference Directory #1* does not mandate a solution set(s) to these potential events, scenarios or topologies. ISO-NE also performs similar assessments with respect to resource adequacy, however, these assessments are not routine and are usually performed on an as needed basis. These analyses typically assess extreme contingency testing, such as a loss of a major gas pipeline, and are performed to determine the effect of

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[247] Within New England, the capacity and load relief benefits from triggering distributed generation, Real-Time Emergency Generation (RTEG), is only attainable through the invocation of ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP 4) – Action 6 of 11.

[248] RTEG is limited to 600 MW in the FCA per the Market Rule III.13.2.3.3.(f) Treatment of Real-Time Emergency Generation Resources: In determining when the FCA is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation (RTEG) resources shall be counted towards meeting the ICR (net of Hydro-Québec Interconnection Capacity Credits (HQICCs)).

[249] 2,035 MW of demand-side resources divided by 32,761 MW of Total Internal Capacity.

[250] Located at: http://www.npcc.org/documents/regStandards/Directories.aspx

[251] This similar type analysis is also mandated within ISO-NE Planning Procedure 03 - *Reliability Standards for the New England Area Bulk Power Supply System* (PP03).

such a contingency on the New England transmission system performance as a measure of system strength. Plans or operating procedures may be developed to reduce the probability of occurrence or to mitigate the consequences that are indicated as a result of the extreme contingency testing. As part of the latest ISO-NE Comprehensive Area Review for year 2013, extreme system condition testing evaluated the loss of an interstate gas pipeline in order to simulate generating unit fuel shortages in New England. The results of the analysis were found acceptable and did not result in the development of any new operating plans or procedures.

On July 1, 2010, ISO-NE received U.S. DOE Smart Grid Investment Grant Award and subsequently began a three-year Synchrophasor Installation and Data Utilization (SIDU) project. The immediate goal of the "Synchrophasor Infrastructure and Data Utilization (SIDU)" project within the New England transmission region is to provide ISO-NE and associated Transmission Owners a significantly expanded base of Phasor Measurement Units (PMUs), Phasor Data Concentrators (PDCs) and communication infrastructure to create the foundation for New England regional Wide Area Monitoring and Situational Awareness (WAMSA) functions. Several Synchrophasor based applications will be developed to take advantage of the newly available data. The longer-term goal of the project is to establish the Phasor technology platform within the region that will enable the deployment and use of Phasor-based tools for system-wide state monitoring and improved reliability and provide a means to mitigate the effect of reliability events. The SIDU Project will enable connections with other external regional PMU projects (*i.e.,* NYISO & PJM) to allow for the sharing of relevant data with external parties in support of reliability management.

Emerging and Standing Reliability Issues

This section identifies and ranks the top emerging and/or standing reliability issues facing the New England subregion in the short and long-term timeframe.[252] This table also identifies the projected (reliability) consequences of each issue coming to fruition and the resultant impacts on ISO-NE system operations.

Problem Summary

Within New England, the existing market design and planning process have fostered significant improvements to the subregion's generation fleet and transmission system. Much of the region's generation now comes from highly efficient, gas-fired combined cycle generators. The transmission system, which for decades saw little investment, has been, and will continue to be upgraded to better serve the region's demand. The amount of demand response has also grown significantly within the region.

Notwithstanding these improvements to the electric power system, recent events have revealed challenges to the continued reliable and efficient operation of New England's bulk power system. If not addressed, these challenges could significantly increase the difficulty of adapting to the substantial changes that are likely to confront the New England power system in the near future.

[252] The short-term timeframe is the summer of 2011 through the winter of 2014/15 (*i.e.,* FCM Window). The long-term timeframe is the summer of 2015 through the summer of 2020 (*i.e.,* Long-Lead Time Window).

Problem Specifics: Short-Term

The short-term challenges involve *(1) resource performance and flexibility*, and, more specifically, the uncertain performance of aging supply-side resources, the uncertain performance of new demand resources, and lack of comparability between new demand-side and supply-side resources. There is a need to increase the flexibility of system operations by increasing operating reserves and ramping capability within certain locations. New England's large supply-source contingencies require significant amounts of reliable and flexible resources to provide necessary operating reserves and the current lack of such resources is a reliability concern.

The failure of resources to perform and concerns over system flexibility also heighten concerns about fuel diversity. Specifically, *(2) increased reliance on natural gas-fired capacity* poses a risk to the New England electric system, as sufficient natural gas may not be available during periods of very high seasonal demand (winter) or when the regional gas transportation system is experiencing problems. To ameliorate this risk, unless the gas-fired resources have a contract for Firm gas transportation or access to a stored supply of gas or an alternate fuel, other resources must be available to respond in a timely manner to make up the capacity deficiencies.

Problem Specifics: Longer-Term

Significant changes to New England's power system will be driven by *(3) the retirement of generators,* which is likely as a result of economic factors and environmental issues and regulations, and *(4) the integration of a greater level of variable resources,* primarily renewable (*i.e.,* wind and solar) energy resources. While integration of variable resources may decrease fuel certainty or diversity concerns, it is unlikely that these variable resources will provide adequate certainty or diversity (particularly under stressed operating conditions) and, in turn, their integration into the power system will require a steady increase in the flexibility of the existing system.

In addition, the ISO and some stakeholders have noted that wholesale markets may not adequately reflect the rapidly-evolving reliability needs that are identified through reliability planning and system operations , and that better *(5) alignment of planning and markets* could create more opportunities for market resources to meet reliability needs, thereby more efficiently managing accelerated resource turnover. Some have requested that the ISO provide analysis on the potential of market resources to address system reliability needs, and others advocate for a regional mechanism that will allow market resources to become economically viable alternatives to transmission, to the extent that they provide a lower-cost reliability solution.[253]

[253] The term "non-transmission alternative" is often used in connection with this issue. ISO-NE is not using that term to characterize the issue because it has become clear that the term is not well-defined, and has been interpreted and used in widely different ways by different stakeholders.

Addressing the Problem

ISO New England has developed a summary document[254] outlining the sequence of solutions to address the above-mentioned short and longer-term challenges. The first stage of the solution, which has a near-term focus, includes enhancing resource performance and accountability by changing resources' information filing requirements and audit procedures related to performance measures and fuel deliverability, and adjusting incentives/penalties related to resource availability and performance. In addition, system reserves and flexibility would be improved by increasing non-spinning reserve and ramping capability in the right locations, allowing closer-to-real-time modification of bids, and eliminating barriers to economic repowering or economic additions on the existing sites of retiring resources, particularly where generation is needed for reliability reasons. ISO-NE would also implement changes to ensure that resource attributes properly reflect constraints, such as restrictions on fuel availability and deliverability, which limit resource availability or performance.

The second stage of the solution is to be implemented over a longer time frame. It involves establishing methods for identifying and evaluating in a consistent manner, from both resource adequacy and system security perspectives, the various potential transmission, generation and demand solutions for identified reliability needs. ISO-NE would also make design improvements to its capacity and reserve markets to procure resources with more precision in particular geographical areas, and with more specific desired performance characteristics, such as operating type (base-load, peaking) or other resource characteristics (*e.g.,* response time, ramp rate). Finally, a process would be established for regularly evaluating and identifying the level of required deliverability and diversity in the resource mix (*e.g.,* the minimum level of non-gas or dual-fuel capability), and how such needs would be translated into capacity and reserve market product definitions and performance requirements.

ISO-NE has been holding discussions with various stakeholders, including individual states, the New England Power Pool (NEPOOL), and the New England Conference of Public Utility Commissioners in order to engage the industry and its regulators in the search for solutions to the identified challenges.

The strategic planning process, consisting of solicitation of stakeholder input and the development of initial changes, is to be completed by the end of 2012. The rule development and stakeholder processes for the first stage will begin in 2012, followed by filing of changes with FERC and then implementation of the changes planned to begin in 2015. The second stage will follow similar steps beginning in 2013.

Assessment Area Description

ISO New England Inc. is a regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, and also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional bulk power system. The New England regional electric power system serves approximately 14.5 million people over a 68,000 square-mile area. New England is a summer-peaking electric system.

[254] This document is located at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/index.html.

NPCC-New York (NYISO)

Introduction

The NYISO is a not-for-profit corporation responsible for operating New York State's bulk electricity grid, administering New York's competitive wholesale electricity markets, and conducting comprehensive long-term planning for the state's electric power system. The NYISO is regulated primarily by the Federal Energy Regulatory Commission (FERC).

The 2011 long-term forecast projects a higher growth rate in Total Internal Demand, compared to last year. The primary drivers for future growth are the increases in population and the economy. New York is promoting a statewide Energy Efficiency policy that is projected to decrease load. Existing capacity resources for 2011 totals 38,887 MW, with *Future-Planned* capacity additions amounting 5,589 MW, of which 1,533 MW are wind units.

New York State is considering a number of environmental initiatives under the Federal Clean Air Act, Clean Water Act and the New York State Environmental Conservation Law that could affect the availability of generation resources in New York and may lead to generator retirements. The NYISO monitors these regulatory initiatives and analyzes their potential reliability impact through its Reliability Planning Process, which is primarily comprised of a biennial Reliability Needs Assessment (RNA) and a Comprehensive Reliability Plan (CRP). At this time there are no environmental or regulatory restrictions that adversely impact reliability during the 2011-2020 timeframe within the NYCA.

The NYISO's Reliability Planning Process is a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over 10-year planning horizons to ensure that the New York State bulk power system meets or exceeds the planned loss of load expectation (LOLE) that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10-years, or 0.1 days per year. Results of the 2010 RNA,[255] published September 2010, demonstrate that the LOLE for the New York Balancing Area (NYBA) does not exceed 0.1 days per year in any year through 2020 under Base Case conditions.

Reliability Assessment

Existing capacity resources for 2011 totals 38,887 MW, as compared to the 39,260 MW reported in 2010. This includes 227 MW of generation retirements. There are also 2053 MWs of Special Case Resources (Demand Response capacity) counted in addition to the 38,887 MW. New capacity additions planned to be in-service over the assessment timeframe total 5,589 MW, of which 1,533 MW are wind units. 597 MW of this new capacity are expected to be on-line for summer 2011. The current Installed Reserve Margin requirement (IRM), as determined by the New York State Reliability Council (NYSRC), for the New York Control Area for the Capability Year 2011-2012 is 15.5 percent. The projected Reserve Margins exceed the current IRM of 15.5 percent throughout the assessment period (Figure 97).

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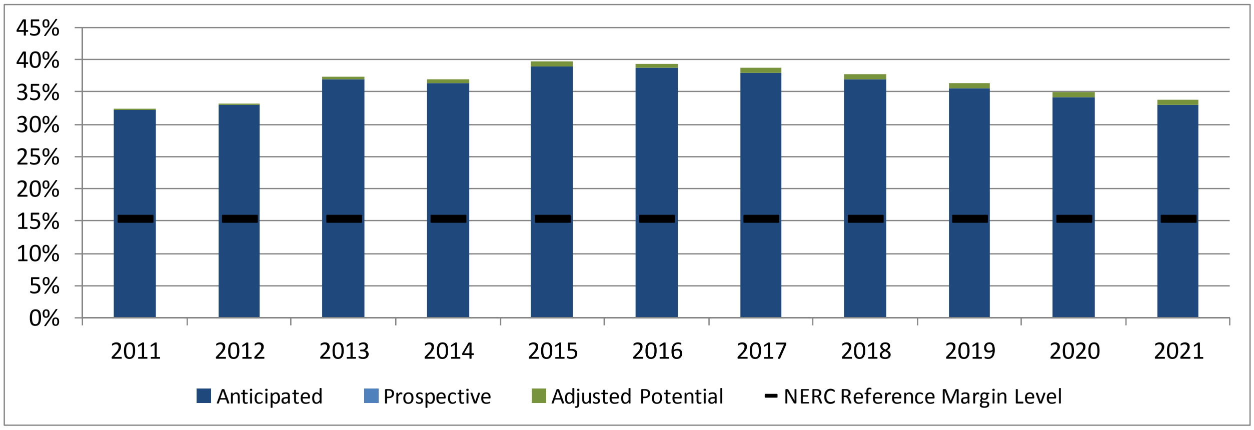
[255] http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

Figure 97: Annual On-Peak Planning Reserve Margins



Comprehensive System Planning Process (CSPP)

Developed with NYISO stakeholders, the biennial Comprehensive System Planning Process (CSPP) combines the expertise of the NYISO and its stakeholders to assess and establish the bulk electricity grid's reliability needs to develop and evaluate solutions to maintain bulk power system reliability, to identify and assess congestion on the bulk power system, and to evaluate potential projects that mitigate such congestion. Each biennial cycle begins with the Local Transmission Owner Planning Process (LTPP). The LTPP provides inputs for the NYISO's Reliability Planning Process. The NYISO then conducts the Reliability Needs Assessment (RNA). The RNA evaluates the adequacy and security of the bulk power system over a 10-year Study Period. In identifying resource adequacy needs, the NYISO identifies the amount of resources in megawatts (known as "compensatory megawatts") and the locations in which they are needed to meet those needs. After the RNA is complete, the NYISO requests and evaluates market-based and regulated backstop and alternative solutions to address the identified reliability needs. This step results in the development of the NYISO's Comprehensive Reliability Plan (CRP) for the 10-year Study Period. The next step of the CSPP is the completion of the Congestion Assessment and Resource Integration Study (CARIS) for economic planning. CARIS examines congestion on the New York bulk power system and the costs and benefits of alternatives to alleviate that congestion. During the second phase of this step, the NYISO will evaluate specific transmission project proposals for regulated cost recovery.

Adequacy is a planning and probabilistic concept. A system is adequate if the probability of having sufficient transmission and generation to meet expected demand is equal to or less than the system's standard, which is expressed as a loss of load expectation (LOLE). The New York State bulk power system is planned to meet an LOLE that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10-years, or 0.1 days per year. This requirement forms the basis of New York's installed capacity (ICAP), or resource adequacy requirement.

Security is an operating and deterministic concept. This means that possible events are identified as having significant adverse reliability consequences, and the system is planned and operated so that the system can continue to serve load even if these events occur. Security requirements are sometimes referred to as N-1, N-1-1 or N-2. N is the number of system components; an N-1 requirement means that the system can withstand single disturbance events (*e.g.,* one component outage) without violating thermal, voltage and stability limits or before affecting service to consumers. N-1-1 means that the reliability criteria apply after any critical element such as a generator, transmission circuit, transformer, series or shunt compensating device, or high voltage direct current (HVDC) pole has already been lost, and after generation and power flows have been adjusted between outages by the use of 10-minute operating reserve and, where available, phase angle regulator control and HVDC control. Each control area usually maintains a list of critical elements and most severe contingencies that need to be assessed.

The Reliability Planning Process is anchored in the market-based philosophy of the NYISO and its Market Participants, which posits that market solutions should be the preferred choice to meet the identified reliability needs reported in the RNA. In the CRP, the reliability of the bulk power system is assessed and solutions to reliability needs evaluated in accordance with existing reliability criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council, Inc. (NPCC), and the New York State Reliability Council (NYSRC) as they may change from time to time. The NYISO also designates the Responsible TO or Responsible TOs to proceed with a regulated backstop solution in order to maintain system reliability in the event that market-based solutions do not materialize to meet a reliability need in a timely manner. Market Participants can offer and promote alternative regulated solutions which, if determined by NYISO to help satisfy the identified reliability needs and by regulators to be more desirable, may displace some or all of the Responsible TO's regulated backstop solutions.

The NYISO does not have the authority to license or construct projects to respond to identified reliability needs reported in the RNA. The ultimate approval of those projects lies with regulatory agencies such as the FERC, the NYS PSC, Federal and state environmental permitting agencies, and local governments. The NYISO monitors the progress and continued viability of proposed market and regulated projects to meet identified needs, and reports its findings in annual plans**.**

The NYISO has established procedures and a schedule for the collection and submission of data and for the preparation of the models used in the RNA. The NYISO's procedures are designed to allow its planning activities associated with the CSPP to be aligned and coordinated with the related activities of the NERC, NPCC, and NYSRC and to be performed in an open and transparent manner. The assumptions underlying the RNA are reviewed at the Transmission Planning Advisory Subcommittee (TPAS) and the Electric System Planning Working Group (ESPWG).

The RNA Base Case consists of the Five Year Base Case and the second five years of the Study Period. The Study Period analyzed in the 2010 RNA is the 10-year period from 2011 through 2020. The load models developed for the RNA Base Case are based on the load forecast from the 2010 Load and Capacity Data report, also known as the "Gold Book". The Five Year Base Case was developed based on: (1) the most recent *Annual Transmission Reliability Assessment* (ATRA) Base Case, (2) input from Market Participants, and (3) the procedures set forth in the CRPP Manual.

The NYISO developed the system representation for the second five years of the Study Period starting with the First Five Year Base Case and using: (1) the most recent Load and Capacity Data Report published by the NYISO on its Web site; (2) the most recent versions of NYISO reliability analyses and assessments provided for or published by NERC, NPCC, NYSRC, and neighboring control areas; (3) information reported by neighboring control areas such as power flow data, forecasted load, significant new or modified generation and transmission facilities, and anticipated system conditions that the NYISO determines may impact the bulk power transmission facilities (BPTF); 4) Market Participant input; and 5) procedures set forth in the CRPP manual. Based on this process, the network model for the second five-year period incorporates TO and neighboring system plans in addition to those incorporated in the Five Year Base Cases. The changes in the MW and MVAr components of the load model were made to maintain a constant power factor.

The RNA Base Case does not include all projects currently listed on the NYISO's interconnection queue or those shown in the 2010 Gold Book. It includes only those which meet the screening requirements for inclusion. Resources that may choose to participate in markets outside of New York are modeled as contracts thus removing their available capacity for meeting resource adequacy requirements in New York.

Principal Findings for the 2010 RNA

The RNA evaluated resource and transmission adequacy for the entire 10-year Study Period. The analysis encompasses the Five Year Base Case and the second five years. The RNA Base Case transfer limits under emergency conditions (from the analysis conducted with the updated base cases) were employed to determine resource adequacy needs (defined as a loss-of-load-expectation or LOLE that exceeds 0.1 days per year).

The transfer limits were calculated for each year of the first five years and for the tenth year of the study period (the end of the second five years). If the transfer limits for the tenth year are extremely lower than fifth year of the study period, and there are Reliability Needs identified, the transfer limits for the second five years are assumed constant at the fifth year values as it can be assumed that the solutions presented would impact the transfer limits. The impact on the transfer limits is determined in the evaluation of solutions to validate this assumption. If not, additional solutions will be developed. For this RNA, actual transfer limits were calculated for year ten and a linear approximation for the annual reduction in limits was assumed.

An important element of performing a transmission security assessment is the calculation of short circuit current to ascertain whether the circuit breakers present in the system would be subject to fault levels in excess of their rated interrupting capability. The analysis was performed for the year 2015 reflecting resource additions, TO Firm plans, and resource retirements. The calculated fault levels would be constant over the second five years because the methodology for fault duty calculation is not sensitive to load growth. Overdutied circuit breakers appear in one substation in the analysis: Farragut. The overdutied circuit breakers at Farragut occur with the addition of two new projects, Bayonne Energy Center (Class Year 2009) and Astoria Energy II (Class Year 2010), connected to the Con Edison and NYPA systems, respectively. The NYISO identifies necessary mitigation solutions for the overdutied breakers and perform cost allocation of any identified upgrades during the applicable Class Year studies pursuant to Attachment S of the NYISO OATT.

The LOLE for the NYCA did not exceed 0.1 days per year in any year through 2020 for the RNA Base Case. Given that the Base Case analysis produced LOLE results that were below 0.1 days per year, for all years in the Study Period, there were no identified transmission security violations for the 10-year Study Period. No additional resources are forecasted to be required to maintain reliability at this time. The 2010 RNA report was reviewed and approved by ESPWG and TPAS, and approved by the NYISO's Operating Committee, Management Committee and Board of Directors and published September 2010.

The NYISO monitors, on a quarterly basis, projects identified in an RNA assessment to determine that those projects remain on schedule. The NYISO also monitors progress on the State Energy Efficiency program implementation, SCR program registration, transmission owners' updated plans, and other planned projects on the bulk power system. Should the NYISO determine that conditions have changed; the NYISO will determine whether market-based solutions or regulated responses are progressing sufficiently to meet the resource adequacy and system security needs of the New York power grid. If necessary, the NYISO will trigger a Regulated Backstop Solution (RBS) to meet the resource or security need. However, if no viable RBS or timely solution exists, the NYISO will issue a request to the Transmission Owners for a Gap solution.

Installed Reserve Margin (IRM), Locational Capacity, and Import Rights

The NYISO also performs three annual studies for reliability purposes. The first is the "New York Control Area Installed Capacity Requirements Study" to help the New York State Reliability Council determine the required Installed Reserve Margin for the upcoming capability year for the New York Balancing Authority area. The current level of the Installed Reserve Margin approved by FERC and the New York State Public Service Commission is 15.5 percent[256] for the 2011-2012 capability year which equates to an Installed Capacity requirement of 37,783 MW. The previous IRM requirement was 18.0 percent

The second study is to determine the Locational Capacity Requirement[257] that must be fulfilled by Load Serving Entities (LSE) in the New York City and Long Island capacity zones. As reviewed and approved by the NYISO's Operating Committee, this study determines the amount of capacity that must be electrically located within specific zones such as New York City and Long Island. The NYISO currently requires that a value of capacity equal to 81.0 percent of the New York City peak load be secured from within its zone and capacity totaling 101.5 percent of Long Island peak load be secured within that zone, for the 2011-2012 capability year. The third study performs an analysis that determines the maximum amount of ICAP contracts that can originate from Balancing Authorities external to the New York Balancing Authority area without violating Reliability Criteria. For the 2011-2012 capability year, contracts totally 2,730 MW may be imported from external areas.

The studies above include only those generation resources that are qualified to participate in New York's Installed Capacity Market and those external resources that have met the NYISO's requirements to

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[256] New York Control Area Installed Capacity Requirements for the Period May 2011 through April 2012 dated December 10, 2010. http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp.

[257] Locational Minimum Installed Capacity Requirements Study - Covering the New York Control Area for the 2011 – 2012 Capability Year: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

deliver capacity to the New York border. New York generation resources that have sold their capacity to external control areas are excluded from the study or are prorated to their capacity that remains in New York.

Demand Response resources are incorporated into these studies as an Emergency Operating Procedure in the MARS software. These resources are modeled with a performance factor to more accurately represent their contribution to demand response. Performance is determined using several methods. The Average Peak Monthly Demand method (APMD) compares the actual hourly interval metered energy with the average peak monthly demand. The Customer Baseline Load method (CBL) compares recent historical data to determine what energy consumption would have been if the participant had not reduced load. Each resource is tested once per capability period. From this data, and actual calls to perform, a performance factor is determined for each resource which more accurately represents the actual demand reduction (MW) expected.

Additional Studies for Resource Adequacy

The Northeast Power Coordinating Council, Inc. (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.

Results of the most recent Comprehensive Review[258] showed that the New York Balancing Area would comply with the NPCC resource adequacy reliability criterion under both the Base Load Forecast and High Load Forecast over the 2010 – 2014 assessment period.

The NYISO performs transient dynamics and voltage studies. There are no stability issues anticipated that could impact reliability during the 2011 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 calculate and analyze system limits and conditions for the upcoming operating period. The operating studies include calculations of thermal transfer limits of the internal and external interfaces of the New York Balancing Authority area. The studies are modeled under seasonal peak forecast load conditions. The operating studies also highlight and discuss operating conditions including topology changes to the system (generators, substations, transmission equipment or lines) and significant generator or transmission equipment outages.

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[258] Comprehensive Review of Resource Adequacy Covering the New York Control Area for the years 2010 – 2014 published March 2010. http://www.npcc.org/documents/reviews/Resource.aspx.

Demand

Last year's annual average growth rate was 0.64 percent from 2009 to 2018. This year's annual average growth rate is 0.67 percent from 2011 to 2021 (Table 87). The slight difference between the 2010 forecast is due to the recovery from the recession in the short-term and additional Energy Efficiency impacts.

Table 87: On-Peak Demand

Demand	2011 (MW)	2021 (MW)	Total Growth (MW)	Average Annual Growth (%)	Assessment Period Change (%)
Total Internal	32,712	35,192	2,480	0.67%	7.6%
Net Internal	30,659	33,139	2,480	0.71%	8.1%

The NYISO develops independent forecasts for each of 11 zones in its control area; the total is based on the sum of the zones. Both coincident and non-coincident peak demands are forecast. The peak producing conditions are based upon the 50th percentile for most regions of the state. However, in certain regions in and around New York City, the peak-producing conditions are more conservative, based upon the 67th percentile. This provides additional reliability for this part of the control area. As a result, the statewide forecast is somewhat higher than a 50th percentile. The weather assumptions and economic assumptions for the 50-50 forecast are normal weather and an eventual recovery from the recession.

Both the current and the previous forecasts have incorporated reductions in peak demand expected to be achieved by statewide Energy Efficiency programs. These programs are funded by the state of New York through system benefits charges applied to all retail rates. The programs are implemented by the New York State Energy Research and Development Agency, the major investor-owned utilities in the state, and by other state power authorities, such as the Long Island Power Authority and the New York Power Authority.

The New York State Public Service Commission (NYS PSC) has ordered the creation of an Evaluation Advisory Group to develop statewide standards for the measurement and verification (M & V) of the impacts of the programs, after they are installed. This group is currently developing M & V protocols that will be followed by program implementers. Monthly program tracking results are provided to the Department of Public Service staff to determine whether program activities are meeting the goals set by the state.

The New York Independent System Operator, Inc. offers two reliability-based Demand Response programs: the Emergency Demand Response Program (EDRP).[259] and the Installed Capacity-Special Case Resource Program (ICAP/SCR). Resources may register for either EDRP or ICAP/SCR, but not both programs during the same capability month; however, resources enrolled in the ICAP/SCR program that

[259] Terms in upper case not defined herein have the meaning ascribed to them in the NYISO's Market Administration and Control Area Services Tariff.

have not sold capacity for the month may participate in an EDRP activation occurring in that same month. Energy Efficiency and Demand-Side Management (DSM) programs in the NYISO Assessment Area are shown below (Table 88).

Table 88: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**370**	**2,972**	**2,602**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	-	-	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	2,053	2,053	-
Total Dispatchable, Controllable Demand Response	**2,053**	**2,053**	**-**
Total Demand-Side Management	**2,423**	**5,025**	**2,602**

EDRP, which also includes the Targeted Demand Response Programs discussed below, provides demand resources with the opportunity to earn the greater of $500/MWh or the prevailing location-based marginal price (LBMP) for energy consumption curtailments provided when the NYISO calls on the resource. There are no consequences for enrolled EDRP resources that fail to curtail. Resources participate in EDRP through Curtailment Service Providers (CSP), which serve as the interface between the NYISO and resources. In NERC's seasonal Assessment and Regional Outlook worksheets, EDRP Resources are reported on line 4d: Demand Response used for Energy, Voluntary Services-Emergency.

The Targeted Demand Response Program (TDRP), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources that have not sold capacity for that month on a voluntary basis, at the request of a Transmission Owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City. Responding resources are eligible for an energy payment during the event, using the same performance calculation as EDRP resources.

The ICAP/SCR program allows demand resources that meet certification requirements to offer Unforced Capacity (UCAP) to Load Serving Entities (LSE). Special Case Resources can participate in the Installed Capacity (ICAP) Market just like any other ICAP Resource; however, Special Case Resources (SCRs) participate through Responsible Interface Parties, which serve as the interface between the NYISO and resources. Resources are obligated to curtail when called upon to do so with two or more hours notice, provided the NYISO notifies the Responsible Interface Party day ahead of the possibility of such a call. In addition, ICAP/SCR resources are subject to testing each capability period to verify that they can fulfill their curtailment requirement. Failure to curtail could result in penalties administered under the ICAP program. Curtailments are called by the NYISO when reserve shortages are anticipated. Special Case Resources are eligible for an energy payment during an event, using the same performance calculation as EDRP resources. In NERC's seasonal Assessment and Regional Outlook worksheets, ICAP/SCR resources are reported on line 2d: Load as a Capacity Resource.

Load reductions for energy payment are determined by comparing the actual metered load during the event or test to an estimate of what the load would have been without the event or test. This method is commonly known as a CBL or Customer Baseline Load method. The energy CBL used by the NYISO is based on the hourly average of the highest five out of the last ten similar days with adjustments for weather permitted.[260]

The NYISO also calculates a capacity performance factor for SCRs. The calculation compares the committed demand level to the metered value during the event or test. The calculated performance factor is used to determine the UCAP that is available from each resource for each Capability Period.[261]

Generation

The on-peak capacity mix and net annual change by fuel type for the NPCC-NYISO Assessment Area are shown below (Figure 98 and Figure 99).

Figure 98: On-Peak Capacity Mix by Fuel Type

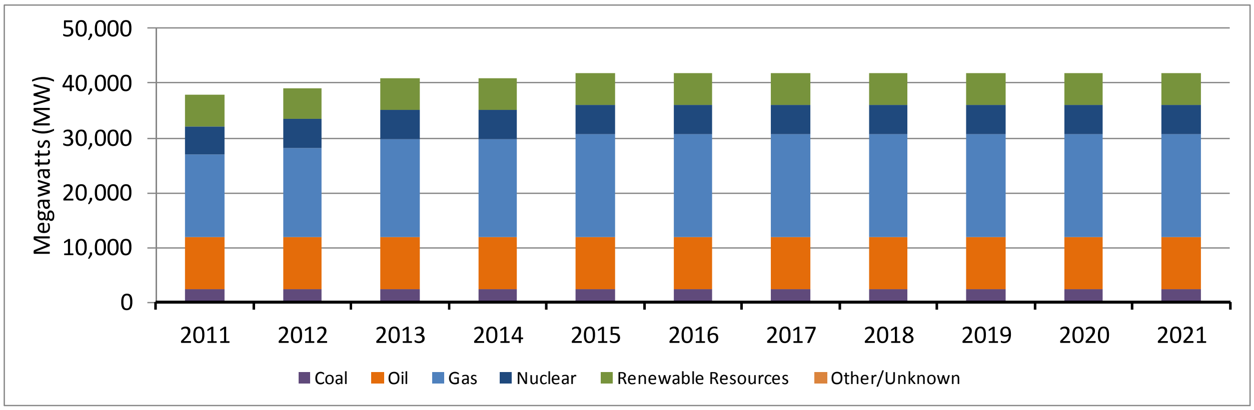
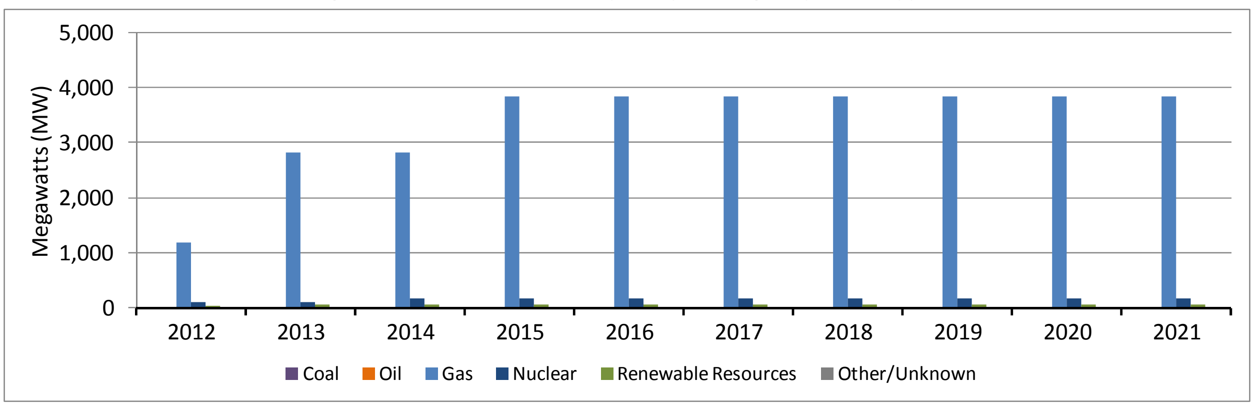


Figure 99: Annual Net Capacity Change by Fuel Type



[260] For additional details, please refer to Section 5.2 of the EDRP Manual on NYISO's website: http://www.nyiso.com/public/webdocs/products/ demand_response/emergency_demand_response/edrp_mnl.pdf.

[261] For more information on the performance calculations for Special Case Resources, please refer to the ICAP Manual on NYISO's website: http://www.nyiso.com/public/webdocs/products/icap/icap_manual/icap_mnl.pdf.

Should natural gas supply shortages arise in New York State in the winter, natural gas-fired units could be forced 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 and older steam units located in load pockets and would impact reliability needs in multiple ways if they were to retire and if replacement capacity with dual fuel capability was not available. The real challenge on a going forward basis will be to maintain the benefits that fuel diversity, in particular dual 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 NYISO categorizes generation capacity fuel types into three supply risks: Low, Moderate and High. The greatest risk to fuel supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is approximately 9,000 MWs greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000 – 26,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10 percent, there is sufficient generation in the low to moderate fuel risk categories to meet the winter electrical peak.

On June 25, 2007, FERC Order 698 incorporated by reference NAESB (North American Energy Standards Board) standards to "establish communication protocols between interstate pipelines and power plant operators and transmission owners and operators." The NYISO has met this requirement with the establishment of communication systems to receive notices of system events, including OFOs (Operational Flow Orders) from interstate pipelines serving generators in New York, and by establishing communication systems to send Energy Emergency Alerts to the Interstate Pipelines. The NYISO will also notify Local Distribution Companies in the event of a system alert. These communication protocols are documented in the Attachment BB of the NYISO OATT (Open Access Transmission Tariff).

The New York Control Area also has a significant amount of hydro resources. Many of these resources are located on rivers throughout the State. The output of these run-of-river resources are subject to water levels which may vary greatly on a month to month basis based upon weather conditions – snowfall amounts, temperature, rainfall amounts, etc. For reliability purposes these units are modeled with a 45 percent derate factor. This derate factor represents a severe scenario case for drought or low water level.

New York models wind resources as load modifiers with a 90 percent summer derate factor for modeling purposes. Hourly wind readings taken at or near each wind resource are converted to hourly unit MW output. Wind density, turbine height, and other factors are taken into account. These hourly MW output values are then netted against the hourly zonal load. New York uses historic hourly wind readings taken in 2002. This wind study year also corresponds to the base hourly load shape year used in New York's resource adequacy studies.

Expected and derated on-peak renewable resources are shown below (Table 89).

Table 89: On-Peak Expected and Derated Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	131	147	16
	Derated	1,180	1,324	144
	Wind - Total Nameplate Capacity	**1,311**	**1,471**	**160**
Solar	Expected	-	14	14
	Derated	-	7	7
	Solar - Total Nameplate Capacity	**-**	**21**	**21**
Hydro	Expected	3,830	3,830	-
	Derated	443	443	-
	Hydro - Total Nameplate Capacity	**4,273**	**4,273**	**-**
Biomass	Expected	360	385	25
	Derated	11	13	2
	Biomass - Total Nameplate Capacity	**371**	**399**	**28**

Existing resources in the New York Balancing Area are shown below by fuel type and by GWh production respectively as published in the NYISO's 2011 Load and Data Report or Gold Book (Table 90).[262]

Table 90: New York Balancing Authority 2011 Generation

Unit Type	MW	Percent of Total
Gas	6415	17%
Oil	3242	9%
Gas & Oil	14275	38%
Coal	2380	6%
Nuclear	5215	14%
Hydro	4274	11%
Hydro (PS)	1404	4%
Wind	1348	<1%
Biomass	371	1%
Total	**38924**	**100%**

The NYISO maintains a list of proposed generation and transmission projects in the NYISO interconnection process. The interconnection process is a formal process set forth in the NYISO Open

[262] Load and Data Report: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

Access Transmission Tariff (OATT) by which the NYISO evaluates the impact of proposed transmission and generation projects on system reliability.

Generation that is identified as *Future-Planned* are the resources that have met sufficient milestones for inclusion in the 2011 Gold Book while the resources identified as *Conceptual* have not achieved these milestones. While these *Conceptual* resources are at various stages of study in the NYISO's interconnection process, at this time the NYISO cannot determine with any certainty which of these projects will proceed to fruition as planned. Currently, there are no planned retirements scheduled over the assessment period. There were 227 MW of retired generation since the publication of the 2010 Gold Book.

Capacity Transactions

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring control areas allowed without violating the LOLE criteria. For 2011/2012, the amount is 2,730 MW (Table 91). Except for grandfathered contracts, these import rights are allocated on a first-come, first-served basis.

Table 91: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	1,821	1,904	965	1,047
	Expected	1,553	1,553	2,041	2,041
	Provisional	-	-	-	-
	Total	**3,374**	**3,457**	**3,006**	**3,088**
Exports	Firm	-	-	-	-
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**-**	**-**	**-**	**-**
	Net Transactions	**3,374**	**3,457**	**3,006**	**3,088**

While capacity purchases are not required to have accompanying Firm transmission, adequate external transmission rights must be available to assure delivery to the NYBA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYCA locality where a minimum amount of Installed Capacity must be maintained. Three such projects are currently in service with a total transmission capability of 1290 MW. Capacity transactions associated with a UDR are considered confidential market data. Only net capacity import totals can be provided to maintain market confidentiality.

NYBA resources that have sold capacity to an external control area are not qualified to participate in the NYISO ICAP Market, and are not counted as resources eligible to meet the NYBA's LOLE reliability criterion for the period the capacity is sold.

Transmission

Con Edison's M29 project consists of a 345 kV cable from Sprainbrook to Sherman Creek across the Dunwoodie South Interface. This project entered service in early 2011. Con Edison is also increasing the rating of two 345 kV cable circuits between Farragut and East 13th St. by installing refrigerated cooling in 2011. Additional local transmission owner plans include reinforcement of the sub-transmission system by Rochester Gas & Electric and Orange & Rockland Utilities.

The interface into southeast New York and New York City could become significantly limiting and impact reliability if there are unanticipated delays in new projects, unexpected retirements, or unanticipated load growth. These scenarios are monitored by the NYISO, and if any happen, the NYISO will determine whether there will be a significant reliability impact. If the impact is imminent, the NYISO will request that the New York Transmission Owners (TOs) implement a Gap Solution under the Comprehensive System Planning Process (CSPP). If a significant reliability impact to the system manifests itself during the next CSPP cycle, the NYISO will address the issue in the next Reliability Needs Assessment.

Operational Issues

There are currently no existing or potential systemic outages that could potentially impact reliability during the 2011-2021 timeframe within the NYCA.

If peak demands are higher than expected the operational measures that can be taken in order to alleviate the situation is to deploy demand response programs and/or reserves. During peak demand periods, the NYISO's demand response programs contribute to maintaining grid reliability.

Various environmental and regulatory policy initiatives are under consideration at both the state and Federal level; however, at this time there are no environmental or regulatory restrictions that adversely impact reliability during the 2011-2020 timeframe within the NYCA. The NYISO will continue to monitor these regulatory efforts and analyze their potential impacts on system reliability going forward.

Emerging and Standing Reliability Issues

The immediate outlook for New York's electric system is positive. As a result of developments that have contributed to a more reliable system over the past decade, as well as planned additions in the near future, the adequacy of power resources is not an imminent concern. However, the sustained adequacy of resources may be challenged by several factors.

Impacts of Federal and State Environmental Regulations

Environmental initiatives that may affect generation resources may be driven by either or both the State and Federal programs. The 2009 New York State Energy Plan provides a long range vision and framework for New York's energy use. The State's Department of Environmental Conservation (NYS DEC) annual publication of its regulatory agenda describes the new environmental initiatives that it will focus on during the coming year. The U.S. Environmental Protection Agency also publishes a similar report on its regulatory agenda.

There are numerous environmental initiatives that may impact the manner in which the existing generating fleet operates or require retrofitting environmental control technologies in order to comply with the new requirements. Several proposals have been identified for which impacts are expected to be widespread and likely to require significant capital investments in order to achieve the new standards.

Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT)

NYS DEC has recently finalized new regulations for the control of emissions of nitrogen oxides (NOx) from fossil fueled power plants. The regulations establish presumptive emission limits for each type of fossil fueled generator and fuel used as an electric generator in New York. NYS DEC is seeking to reduce emissions from the affected generators by 50 percent, from 58,000 Tons per Year (TPY) to 29,000 TPY. Compliance options include averaging emissions with lower emitting units, fuel switching, and installing emission reduction equipment such as low NOx burners or combustors, or selective catalytic reduction units.

The NYISO retained GE to conduct a detailed study about the types and costs of control technology necessary to comply with the proposed regulation. The study found that “A total of 72 units or 9515 MW of capacity was identified as needing some type of control mechanism or equipment modification to comply with the proposed standard.” The study concluded that the costs to comply with the NOx RACT regulation would reduce operating margin for affected generators, but taken alone would generally not lead to situations where those margins would become negative. In addition, the study concluded that the proposed compliance deadline should be extended to July 2014 in order to accommodate the outage schedules necessary to install the required emissions control equipment retrofits. In its final regulation, the NYS DEC adopted the study’s July 2014 recommendation.

Best Available Retrofit Technology (BART)

The New York State Department of Environmental Conservation (NYS DEC) recently promulgated a new regulation Part 249, Requirements for the Applicability, Analysis, and Installation of Best Available Retrofit Technology (BART) Controls. The regulation applies to fossil fueled electric generating units built between August 7, 1962 and August 7, 1977 and is necessary for State to comply with provisions of the Federal Clean Air Act that are designed to improve visibility in National Parks. The regulation requires an analysis to determine the impact of an affected unit’s emissions on visibility in national parks. If the impacts are greater than a prescribed minimum, then emission reductions must be made at the affected unit. Emissions control of sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter (PM) may be necessary. The compliance deadline has been set as January 2014.

The impact assessment of the BART program is less certain than the assessment for the NOx RACT program. The results of the visibility analysis are used to determine the emission reductions that may be necessary for SO2, NOx, and PM. 8940 MW of capacity has been identified as affected. The majority of these units are located in SENY and, are large oil fired units that have gas as an alternate fuel. Many of these units do not have state of the art emission control systems. Units that have natural gas capabilities may be able to sufficiently reduce emissions through the use of distillate fuels or natural gas. Facilities that are predominantly coal-fired may need upgraded particulate collection, SCR, and Flue Gas Desulfurization (FGD).

The NOx control measures for BART generally were consistent with the results of the NOx RACT study. NYS DEC has established a reasonableness test of $5000/ton reduced. This NYS DEC estimate is based on the NYS DEC definition of "Potential to Emit." Capital expenditures for this program would be of the same order of magnitude as the NOx RACT program.

Maximum Achievable Control Technology (MACT)

In March 2011, EPA submitted the Electric Generating Units (EGU) Maximum Achievable Control Technology (MACT) rule for publication in the Federal Register. The proposed MACT rule affects coal- and oil-fired steam generating units. The MACT rule regulates emissions of the hazardous air pollutants (HAP). For coal-fired EGUs, EPA proposed Mercury (Hg), Particulate Matter (PM), and Hydrogen Chloride (HCl) limitations. EPA uses total PM as a surrogate for the non-Hg metallic HAP and HCl as a surrogate for the acid gas HAP. For liquid oil-fired EGUs, EPA proposed total HAP metal (including Hg), HCl, and Hydrogen Fluoride (HF) emission limitations. The total HAP metal is the sum of Hg and non-Hg HAP metals including Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se). EPA proposed the emission limitations based on the average emissions achieved by the best performing twelve (12) percent of the existing sources.

The potential impact of the MACT regulation was estimated by comparing historic emissions of target HAPs using USEPA AP 42 factors and reported Toxic Release Inventory (TRI) data. This review determined that one major facility that primarily consumes coal could be a candidate for a significant environmental control technology retrofit. A similar approach identified eight major generating facilities which represent 8,534 MW of capacity which would be significantly affected by the proposed rule. These facilities could comply by switching to increased use of natural gas or distillate fuels.

Clean Air Transport Rule (CATR)

In August 2010, EPA proposed the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate and Ozone (CATR). In the document, EPA proposed three (3) options to address the judicial opinion on 1997 NOX SIP call and 2005 Clean Air Interstate Rule (CAIR). The three options are: State Budgets/Limited Trading; State Budgets/Intrastate Trading; and Direct Control.

The alternative allocation table issued by EPA in January 2011 is used to compare with each unit's 2008 and 2009 emissions. The required reduction level is calculated for each unit using 2008 emissions as the baseline. EPA identified seven (7) plants for additional NOX control and three (3) sites for additional SO2 control. The NYISO review identified an additional five (5) sites for NOX control and two (2) sites for SO2 control. However, two of the identified SO2 control sites by EPA, Cayuga 1&2, have already installed scrubbers. The total number of units that require retrofit is 11 which represent 2902 MW of capacity.

Best Technology Available (BTA)

In 2010 NYS DEC released a draft policy "Best Technology Available (BTA) for Cooling Water Intake Structures". The proposed policy would apply to plants with design intake capacity greater than 20 million gallons/day and prescribes reductions in fish mortality. The proposed policy establishes performance goals for new and existing cooling water intake structures. The performance goals call for the use of wet, closed-cycle cooling systems at existing generating facilities. The policy does provide some limited relief for plants with historical capacity factors less than 15 percent. This policy is more stringent than the recently released U.S. EPA Rule 316b.

Once the NYS DEC has made a determination of what constitutes BTA for a facility, the Department will consider the cost of the technology to determine if the costs are "wholly disproportionate" to the environmental benefits to be gained with BTA.

Although the number of impacted MWs is unknown, for study purposes the NYISO shows a range from 4410 MW to 7376 MW. This program may require capital investments that are one to two orders of magnitude greater than the cumulative costs for the other environmental initiatives examined. Consequently, the BTA program has the greatest potential to lead to unplanned retirements.

The NYISO will continue monitoring and evaluating the potential reliability impact of new and proposed environmental regulations to determine if conditions have changed during the planning cycle. The NYISO will address any newly identified Reliability Need in the subsequent RNA or, if necessary, issue a request for a Gap solution.

Project Lead Times

As New York State works to sustain and enhance environmental quality, attention must also be paid to the cumulative impact of impending Federal and state environmental regulations on the continued operation of various existing power plants. The proposed regulations are estimated to impact more than half the installed generating capacity in the state. Considerable lead-time is required for power infrastructure project execution, given the time frames needed to finance, permit, and construct major energy projects. The planning horizons of policy makers and regulators should encompass the time required for the electric industry to address new laws and changes in regulatory requirements.

For example, as reported in the 2010 RNA/CRP, a scenario analysis was done to consider the impact on reliability if the Indian Point Plant were to be retired at the latter of the current license expiration dates using the RNA Base Case load forecast assumptions. If the Indian Point Plant were to retire, it would be necessary to develop adequate replacement generation to prevent violation of mandatory resource adequacy reliability standards and maintain the supply of power and transmission voltage support needed to move electricity over power lines to serve customer demands in southeastern New York.

Aging infrastructure

The expected adequacy of New York's power resources over the next decade does not diminish the need to address aging generation and transmission infrastructure. As of the close of 2010, 60 percent of

New York State's power plant capacity was put into service before 1980. Similarly, 85 percent of the high-voltage transmission facilities in New York State went into service before 1980.

When reliability needs are identified, solutions (generation, transmission, or demand-side measures) are solicited through the NYISO's Comprehensive System Planning Process. Competitive market-based solutions are given first priority because of their reduced risk to rate-paying consumers.

As a complement to the NYISO planning process, the owners of the interconnected electricity transmission facilities in New York State initiated the State Transmission Assessment and Reliability Study (STARS), which is evaluating New York's existing transmission assets and identifying potential economically beneficial transmission projects that would reliably support New York State's energy needs well into the 21st Century. This effort includes life extension and modernization of existing facilities as well as potential expansion of transmission capabilities in existing transmission corridors to address constraints and congestion.

Assessment Area Description

The New York Independent System Operator (NYISO) is the only Balancing Authority in the New York Control Area (NYCA). The NYCA is a single state ISO (NYISO),[263] formed as the successor to the New York Power Pool, a consortium of the eight investor-owned utilities, in 1999. The NYISO manages the New York State transmission grid encompassing approximately 10,892 miles of transmission lines, serving the electric needs of over 48,000 square miles with a total population of about 19.4 million people. The Assessment Area experiences peak load during the summer season, with the all-time peak load of 33,939 MWs, established during the summer of 2006.

[263] http://www.nyiso.com.

NPCC-Ontario (IESO)

Introduction

Ontario was traditionally a winter peaking system. Since 1998 the system has been summer peaking in eleven of those thirteen years. The 2010 summer actual peak demand was 25,075 MW which was more than 1,500 MW higher than last year's *2010 Long-Term Reliability Assessment* projection of 23,500 MW. The peak was driven by hotter than normal weather conditions. This year's forecast projects summer peak demand to decline from 23,500 MW in 2011 to 22,150 MW in 2021. Likewise, overall energy demand is expected to average an annual growth rate of -0.1 percent over that time period. Existing resources including demand response connected to the IESO-controlled grid is about 36,700 MW. The Certain capacity is almost 31,100 MW. About 1,300 MW of new generation was added since last year. Most of the new addition was from gas-fired generation (1,000 MW). Four coal units with an installed capacity of almost 2,000 MW were shut down in October of 2010. Two additional units at Nanticoke are expected to be shut down by the end of 2011. All coal-fired plants in the province will be phased out by 2014. The Ontario Power Authority (OPA) will negotiate a contract for biomass fuelled generation from Atikokan Generating Station. The conversion of two units at Thunder Bay Generating Station to run on natural gas will start over the period leading up to 2014. Pickering Nuclear Generating Station is scheduled for retirement, but the feasibility of extending the operating life of the Pickering generating units is being studied and the government expects to make a decision by 2012. Bruce and Darlington Nuclear Generating Stations will be refurbished in the latter half of the 10-year period. The conversion to natural gas of some (or all) remaining units at Lambton and Nanticoke will be considered under a range of different scenarios for nuclear generation and system peaking requirements. The Reserve Margins projected over the 10-years are all above the provincial target.

New series capacitors were installed in 2010 at Nobel Transmission Station (TS) on two 500 kV circuits to increase the transfer capability of the Flow-South Interface. A new 176 km (110 mile) 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) is being constructed with completion expected in 2012. This new line is required to accommodate the output of all eight generating units at the Bruce complex and the existing and future renewable generating capacity within the area.

The integration of variable wind and solar generation is an important challenge on which the IESO has been focusing, as the amount of renewable distributed and grid-connected generation grows in the province. There are a number of ongoing initiatives that will help ensure reliability going forward, namely centralized forecasting, visibility of distributed generators to the system operator and dispatchable capability of variable generators.

Reliability Assessment

IESO reliability assessments include multi-area resource adequacy modeling and transmission adequacy assessments that are conducted to determine the deliverability of resources to load. Related assessment criteria and processes are described in the documents *Methodology to Perform Long-Term Assessments*[264] and *Ontario Resource and Transmission Assessment Criteria*.[265]

Every quarter the IESO prepares an 18-Month Outlook, which advises market participants of the resource and transmission reliability of the Ontario electricity system. Specifically, the Outlook assesses potentially adverse conditions that may be avoided through adjustment or coordination of generation and transmission maintenance schedules. In addition, the Outlook reports on initiatives that are being put in place to improve reliability over the 18-month forecast timeframe.

Once a year, the IESO reviews and assesses the adequacy of the Ontario system for the next five years. The key findings stemming from this adequacy assessment are published in the *Ontario Reserve Margin Requirements* report.[266] The required reserve levels are determined based on probabilistic methods deemed by NPCC to be acceptable for meeting regional loss of load expectation (LOLE) criteria. The target Reserve Margin levels for the first five years range from 21.3 percent in 2011 to 19.8 percent in 2015. The OPA target Reserve Margin of 20 percent is applied beyond 2015.

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

The reserve requirements are met solely with *Existing-Future* and *Conceptual* resources that are internal to Ontario. However, the IESO participates in the inter-area simultaneous activation of 10-minute reserve (SAR) with ISO-NE, NYISO, the Maritimes and PJM. NPCC Directory #5 describes the implementation of SAR program in which two or more Balancing Authorities agree to individually maintain but jointly activate 10-minute reserve to facilitate a rapid recovery from a significant contingency or to manage stressed system conditions. Projected Reserve Margin requirements are determined on the basis of the NPCC regional criteria for the short-term as well as the long-term.

Operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC and MRO include contractual provisions for emergency imports directly by the IESO. These agreements are respected during supply shortage conditions.

Distributed generation is decremented from the total demand to determine the demand on the grid. Over 900 MW of distributed generation is installed in the distribution system. The amount of distributed generation is expected to increase to 6,500 MW by 2018.

[264] http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2011may.pdf

[265] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

[266] http://www.ieso.ca/imoweb/pubs/marketReports/Ontario-Reserve-Margin-Requirements-2011-2015.pdf

The IESO and the OPA recognize the potential for certain adverse conditions such as extended forced outages or dry conditions and particular fuel interruptions to result in higher than expected resource unavailability and establish planning reserves sufficient to handle many of these conditions. To the extent resource procurement exceeds the planning reserve requirements, resource adequacy can be maintained for higher than normal contingencies. However, there are always conditions which can exceed those planning assumptions. In such adverse situations the IESO's operations would rely on interconnection support and available control actions to maintain system reliability. Through retention and further development of a diverse resource mix, the potential consequence of these events is reduced.

The IESO assessments of resource adequacy recognize the supply limitations associated with transmission-limited resources. Transmission limits are modeled on a zonal basis and recognize transmission improvements which will result from implementation of the OPA's transmission plan. There are no resources categorized as energy-only in Ontario. All the resources are attributed a certain capacity.

In November 23, 2010, the Government of Ontario released its Long-Term Energy Plan (LTEP), specifying the target for large scale development of renewable energy projects and implementation of Conservation. The renewable resources target for wind, solar and biomass is 10,700 MW by 2018, accommodated through transmission expansion and maximizing the use of the existing system. Ontario will grow its clean energy portfolio through the continuation of programs like the Feed-in Tariff (FIT) and microFIT.

Ontario will continue to grow its hydroelectric capacity, with a target of 9,000 MW by 2018. This will be achieved through the development of new facilities and through significant investments to maximize the use of Ontario's existing facilities.

The Government of Ontario has set a Conservation target at 7,100 MW and will reduce overall demand by 28 terawatt-hours (TWh) by 2030. For assessment purposes, variable generation such as wind and solar are treated as capacity resources with capacity contribution values based on historical output at the time of seasonal peak demand (see Generation section for detailed description).

The IESO's Renewable Integration Initiative is launched to prepare power system operations and the IESO-administered markets to accommodate Ontario's growing renewable generation. The focus of this initiative is on forecasting, visibility and dispatch. In this context, with stakeholder consultations, the IESO has developed associated design principles for incorporating larger volume of variable generation in Ontario's electricity system.

The IESO will implement a centralized forecast system for wind resources directly connected to the IESO-controlled grid and for wind resources with an installed capacity of 5MW or greater connected to a distribution system. Centralized forecasting will be expanded to include other variable resources such as solar as the total installed capacity becomes more certain.

Demand response programs in Ontario are treated as a supply resource with discounted capacities associated with the unique characteristics of each program (*e.g.,* voluntary/Firm contracts). The OPA manages contracts for the majority of the demand response programs scheduled to be activated over the forecast timeframe. Programs with Firm contracts to reduce demand during periods of high demand/tight supply are expected to provide a reliable and verifiable supply resource.

Unit retirements are expected to occur throughout the assessment timeframe which will have a significant impact on reliability. Two additional units at Nanticoke are expected to shut down by the end of 2011. All coal-fired plants in the province will be phased out by 2014. Eleven coal-fired units will be shut down, representing approximately 4,500 MW of resources across four facilities. The OPA will negotiate a contract for biomass-fuelled generation at the Atikokan Generating Station. The conversion of two units at the Thunder Bay Generating Station to run on natural gas will start over the period leading up to 2014.

Pickering Nuclear Generating Station is scheduled for retirement, but the feasibility of extending the operating life of the Pickering generating units is being studied and the government expects to have an update in 2012. Bruce and Darlington Nuclear Generating Stations will be refurbished in the latter half of the 10-year period. Conversion of some or all of the remaining units at Lambton and Nanticoke to natural gas will be assessed under a range of different scenarios for nuclear generation and system peaking requirements. The Ontario government will make a decision on conversion of some or all of these units in 2012, after work on the continued operation of units at Pickering Nuclear Generation Station and the refurbishment work at Bruce and Darlington is further advanced, providing better information on the availability of nuclear capacity.

Measures taken to mitigate reliability concerns include the development of an integrated planning process for Ontario. This process considers expected and potential unit refurbishments or retirements and proposes ways to meet resulting resource requirements. Specific considerations include the procurement of Conservation programs, renewable resources, new gas-fired units, and procurement of refurbished or new nuclear resources. In addition, the process considers the expansion of transmission that would be required to integrate all of the above-mentioned resources. Other options include developing greater coordination and flexibility related to nuclear refurbishment outages and converting existing coal stations to alternate fuels. Mitigation of reliability concerns is to be supported through ongoing monitoring, assessment, measurement, verification and regular updates of the integrated plans at three-year intervals.

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 contingencies. There are several systems used for localized voltage control in the event of an outage to local supply facilities.

The majority of the special protection systems (SPS) that are in use within Ontario are intended to address the effects of contingencies under outage conditions and are not intended to avoid or delay the construction of bulk transmission facilities. The principal exception is the north-east load and generation rejection SPS that mitigates the effects of contingencies involving the single 500 kV circuit that services this area. This SPS is designed to achieve a post-contingency match between the load and available generation in the area to make the subsequent island viable.

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 comprises 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 processes are activated. The CMST also performs regular test activations.

During the nine-day capacity and energy emergency that followed the August 2003 blackout, the CMST managed the emergency via 31 conference call meetings and was instrumental in producing media messages, facilitating the government's appeal and direction for reduced demand, and obtaining the necessary environmental variances to secure additional supply.

A previous reliability concern in Ontario centered around the loss of 500/230 kV transformer capability in the Toronto area under high load conditions. This has been mitigated by local generation development, moderated demand levels and an autotransformer replacement program to improve the replacement timing should an autotransformer fail.

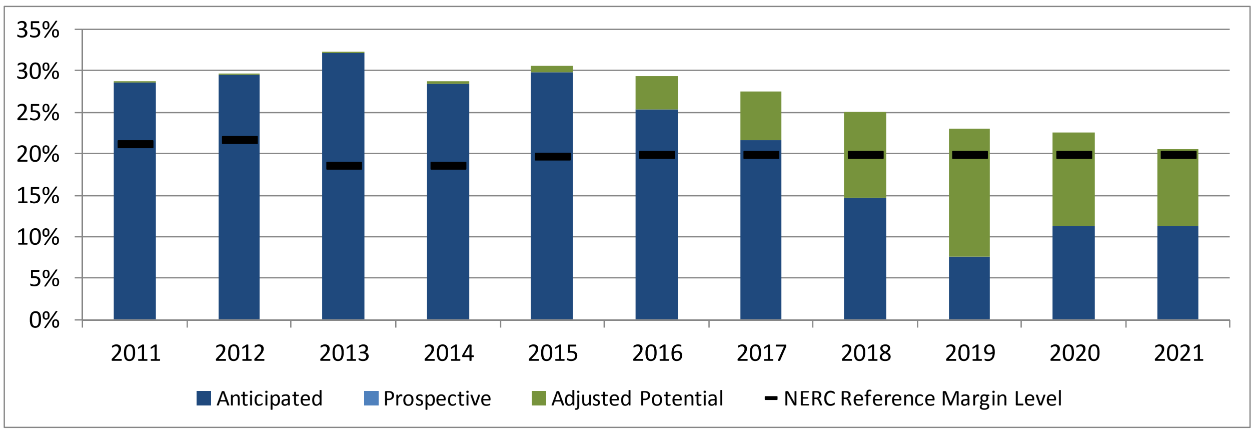
The IESO has facilities in place to monitor the geomagnetically induced currents at specific locations on the system and to initiate alarms when particular thresholds are exceeded. In response to any associated increases in the negative phase sequence currents, pre-defined mitigating measures would be initiated to ensure that the subsequent tripping of any generating units is limited to a manageable amount and that the resultant flows and voltages are within acceptable limits.

In 2010, the IESO conducted an Intermediate Review of Transmission Adequacy which assessed the IESO-controlled grid's conformance with the NERC TPL-001-0 to TPL-004-0 standards and NPCC's more stringent planning criteria (Directory #1 – Design and Operation of the Bulk power system), and the IESO's reliability criteria. The Ontario power system, including the proposed generation and transmission changes up to 2015, is in conformance with the applicable NPCC criteria and NERC standards. The proposed changes and additions to the existing power system in Ontario will not adversely affect the reliability of the Eastern Interconnection.

The IESO has market rules and connection requirements that establish minimum dynamic reactive requirements, and the requirement to operate in voltage control mode for all resources connected to the IESO-controlled grid. In addition, the IESO's transmission assessment criteria include 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 planning and connection assessment studies. Seasonal operating limit studies review and confirm the limiting phenomena identified in planning studies. The SVCs being installed at Nanticoke SS and Detweiler TS, together with the shunt capacitor banks at Middleport, Nanticoke & Buchanan, are intended to ensure that adequate dynamic reactive supplies remain available following the planned shut-down of Nanticoke GS. The new generating stations at Sithe-Goreway and Halton Hills will also ensure the availability of adequate dynamic reactive support in the Greater Toronto Area to supply the projected demand.

The IESO requires a 10 percent margin from the knee of the PV curve to be maintained for pre-contingency voltage stability and a margin of 5 percent to be maintained for post-contingency stability (Figure 100). All analysis is performed with system loads modelled as 'constant MVA.'

Figure 100: Annual On-Peak Planning Reserve Margins



The IESO has advanced the development of an on-line limit derivation tool to maximize transmission capability in the operating time frame. The initial software development has been completed, and business processes have been revised to introduce the initial stages of tool capability province wide.

A web-based online outage requests tool is being introduced for Market Participants to submit their outages directly into the Integrated Outage Management System. The new tool replaces a manual process and is a marked improvement in efficiency, with validation and alerts for short notice requests built into the online tool. All Market Participants are soon expected to use the new tool.

By 2011, most Ontario households and small businesses, totalling 4.5 million consumers, will switch to time-of-use rates, where the price of electricity depends on when it is used. Several electricity distributors have already rolled out time-of-use rates in their respective service territories.

In 2008 the IESO initiated the Ontario Smart Grid Forum, a broad-based industry working group focused on developing a vision for a provincial smart grid that will provide consumers with more efficient, responsive and cost effective electricity service. The second report on the key findings and recommendations of the forum was released in May 2011.[267] The report highlighted a series of recommendations to build on the province's momentum in creating a smarter, more efficient electricity system that delivers direct benefits to consumers and the broader economy.

Ontario Power Generation (OPG) is required to meet strict government-mandated greenhouse gas emission targets. For example, OPG is required to ensure that annual emissions between 2011 and 2014 are two-thirds lower than 2003 levels and that all coal units will be phased out by 2014. As described in the Operational Issues section, a number of infrastructure projects, including transmission improvements, are currently underway to achieve these objectives.

The proposed Oakville plant in the southwest Greater Toronto Area is no longer required due to changes in demand. The need and timing for a future transmission solution in the area is being assessed. No other major generation or transmission projects have been cancelled or significantly deferred that affect reliability.

Demand

This year's demand forecast net of conservation has an average annual growth rate of -0.55 percent over the period 2011-2021 compared to last year's average growth of -0.30 percent for the years 2010-2019 (Table 92). The average growth rate is higher this year due to stronger demand growth driven by economic and demographic factors. However, demand growth continues to be negative as a result of Conservation efforts and growth in embedded (distributed) generation over this long-term assessment period.

Table 92: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	23,539	22,142	(1,397)	-0.55%	-5.9%
Net Internal	22,373	20,540	(1,833)	-0.77%	-8.2%

Ontario's forecast of demand is based on Monthly Normal (50/50) weather. The economic forecast is based on the most recent available information and predicts modest but stable economic growth. Electricity demand is expected to lag the general economic recovery as Ontario's economy continues to evolve and mature. This economic evolution has led to a decline in importance of large energy-consuming sectors of the economy such as primary industries and manufacturing, to less energy-intense activities like financial services, technology and multimedia. Given a lower and slower rate of underlying growth, Conservation savings and increasing embedded generation capacity are expected to more than offset the electricity demand growth fuelled by economic expansion and population growth. The IESO's reliability analysis is based on this demand forecast.

[267] http://www.ieso.ca/imoweb/pubs/smart_grid/Smart_Grid_Forum-Report-May_2011.pdf.

The forecast of Ontario peak demand is the system peak demand and therefore represents the coincident peak demand of Ontario's 10 main sub-areas or zones. All analysis is done on the system peak demand.

The Ontario Power Authority (OPA) and electricity distributors are responsible for delivering Conservation programs throughout the province. To date, there are a number of Conservation- related initiatives that will reduce electricity demand. These programs range from lighting and appliance replacement to building retrofits targeted towards the residential, commercial, and industrial sectors. Measurement and verification are the responsibility of the OPA as part of their mandate. Incremental Conservation savings are expected to reach 3,900 MW over the forecast horizon.

Demand Response within Ontario includes a number of different programs (Table 93). Some wholesale customers in the province bid their load into the market and are responsive to price through IESO dispatch instructions. Other customers have been contracted by the OPA to provide demand response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and currently amounts to slightly more than 1,500 MW in total, of which 48 percent is included for seasonal capacity planning purposes, with half of the included amount categorized as interruptible. This amount is expected to grow over time as more loads are contracted to respond to tight supply conditions. By the end of the forecast, the interruptible capacity component is expected to grow by nearly 800 MW—about half counted for seasonal capacity planning purposes. The impacts of these initiatives are reflected in the reliability analysis.

Table 93: Summer On-Peak Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**1,260**	**4,791**	**3,530**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	-	-	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	1,166	1,602	436
Total Dispatchable, Controllable Demand Response	**1,166**	**1,602**	**436**
Total Demand-Side Management	**2,426**	**6,392**	**3,966**

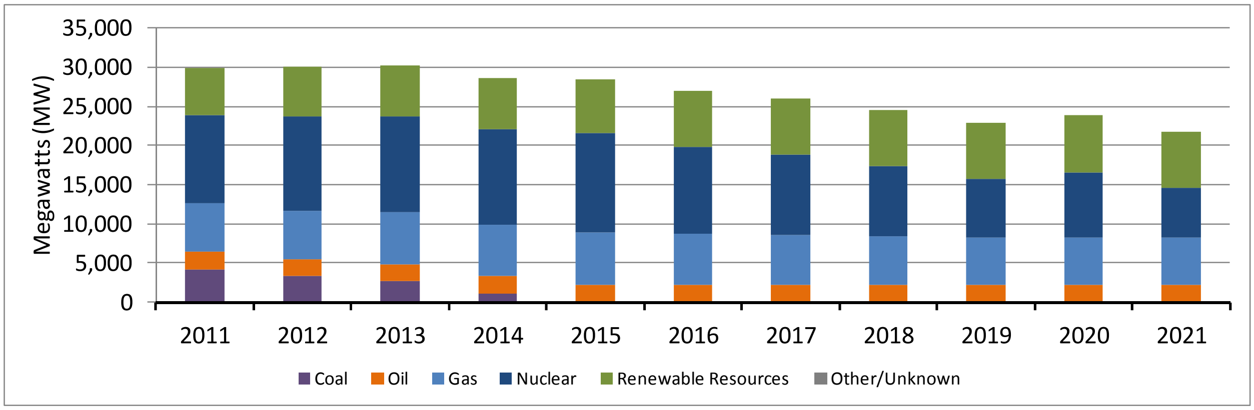
Ontario does not have renewable portfolio standards. However, there are a number of initiatives and programs that are expected to generate Conservation savings and demand response. This information is incorporated in the IESO's reliability analysis.

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.

Generation

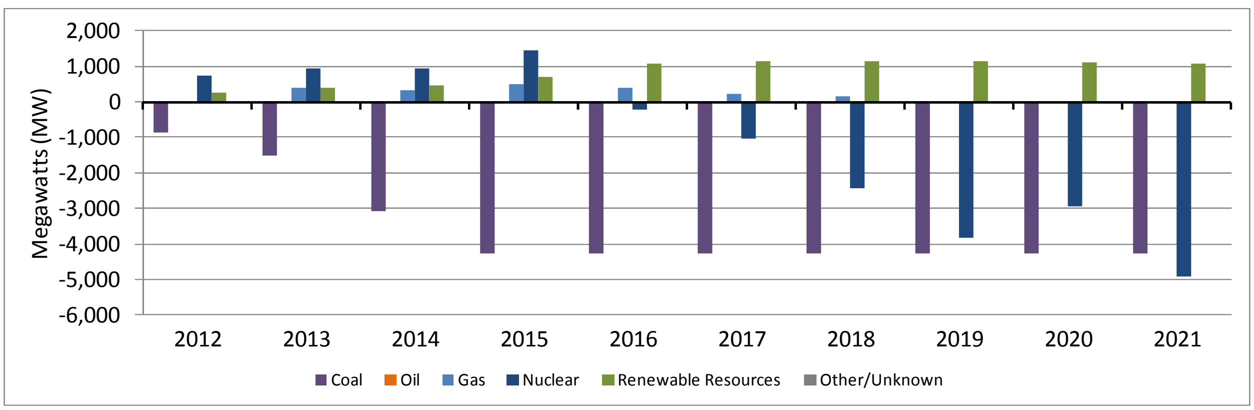
For summer 2011, the total *Existing-Certain* capacity resources connected to the IESO-controlled grid is 31,094 MW. The capacity mix by fuel type is shown below (Figure 101)

Figure 101: On-Peak Capacity Mix by Fuel Type



Existing-Inoperable capacity amounts to 28 MW. Approximately 9,800 MW of *Future-Planned* and *Conceptual* renewable resources are expected to come on-line by 2018. This amount includes resources that are embedded and grid-connected. This is made up by more than 6,300 MW of wind, 2,200 MW of solar, 900 MW of hydroelectric and 400 MW of biomass (Figure 102).

Figure 102: Annual Net Capacity Change by Fuel Type



As of spring 2011, the existing installed capacity of wind generation resources on the IESO-controlled grid is 1,334 MW. 13 percent of the installed wind capacity is assumed to be available at the time of summer peak, and thirty-two percent is assumed to be available at the time of winter peak. Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (percent of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data, and the simulated 10-year historic wind data will continue until 10-years of actual wind data is accumulated, at which point the simulated wind data will be phased out of the WCC calculation. The WCC values are updated annually.

Ontario's solar capacity value is forecast to be 40 percent of installed for the summer peak and no contribution for the winter peak. The values are based on historical modeled photovoltaic output data at the time of summer and winter peaks. No derated value is projected for biomass generation. It is assumed that the full installed capacity will be available at the time of the peak. The data below represents only *Future-Planned* and *Future-Other* resources, excluding any *Conceptual* projections (Table 94).

Table 94: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	173	650	476
	Derated	1,161	4,347	3,187
	Wind - Total Nameplate Capacity	**1,334**	**4,997**	**3,663**
Solar	Expected	-	42	42
	Derated	-	63	63
	Solar - Total Nameplate Capacity	**-**	**105**	**105**
Hydro	Expected	5,693	6,016	324
	Derated	2,131	2,265	133
	Hydro - Total Nameplate Capacity	**7,824**	**8,281**	**457**
Biomass	Expected	47	290	244
	Derated	-	1	1
	Biomass - Total Nameplate Capacity	**47**	**291**	**244**

Assumptions related to amounts and types of *Future-Planned* and *Conceptual* capacity resources are derived from the Ontario Power Authority. The OPA is the electricity system planner for the province of Ontario.

The OPA's statutory objects include some of the following requirements: to ensure adequate, reliable and secure electricity supply and resources in Ontario and to conduct independent planning for electricity Conservation, demand management, renewable and other generation, and transmission over the long-term.

Generation resources identified for reliability analysis include:

- Those which are currently in operation;
- Those which are not currently in operation but are anticipated to enter service in the future as a result of an executed financial contract with the OPA or an existing or anticipated government directive; and
- Those *Conceptual* resources identified in longer-term power system planning scenarios developed by the Ontario Power Authority.

An adjustment or confidence factor was not applied to *Conceptual* resources for purposes of this assessment. Planning scenarios are developed by the OPA on an ongoing basis as part of its regular planning activities. *Conceptual* resource projections were reviewed within the planning processes used in preparation for this assessment.

Resources have been identified and categorized consistent with the planning assumptions of the OPA. These planning assumptions reflect the anticipated take-up of renewable energy procurement initiatives administrated by the OPA, sequencing of associated transmission developments, projections around nuclear refurbishments and other projections.

Capacity Transactions

No Firm, Expected or Provisional imports into Ontario or exports to other regions during on-peak periods are projected in this long-term assessment period.

Transmission

Construction of a new 176 km (110 mile) 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) is in progress, with completion expected in 2012. This new line is required to accommodate the output of all eight generating units at the Bruce complex together with approximately 500 MW of existing wind generating capacity, as well as a further 1,250 MW of new renewable generating capacity that is forecasted for development within the area. With the new generating facilities, the combined generation in the Bruce area is projected to exceed 8,100 MW. The completion of the Bruce to Milton line has been delayed due to easement and right-of-way acquisition. If the current schedule for the return to service of the two Bruce units is maintained, then the units will be in-service before the new 500 kV line. Although the installation of the new SVCs at Nanticoke and Detweiler will improve the transfer capability from the Bruce area there could be periods when the new generation will need to be constrained until the new line is completed.

The existing SPS will also be enhanced not only to accommodate the two new 500 kV circuits between the Bruce complex and Milton SS but also to address other contingency conditions not presently covered by the SPS. The intent of the expanded coverage is to limit the extent of restrictions imposed on the output from the Bruce units during transmission element outage conditions while also assisting with the re-preparation of the system following a permanent fault when subsequent contingency conditions may become more critical. This SPS will be a permanent feature to deal with contingencies and is not intended to avoid or delay the construction of bulk transmission facilities. The new scheme is scheduled to be in service by late 2013.

To coincide with the completion of the new Bruce to Milton 500 kV line, a 350 MVAr SVC is to be installed at Nanticoke SS, connected to the 500 kV busbar, and another 350 MVAr SVC is to be installed at Detweiler TS, connected to the 230 kV busbar. These SVCs are required to provide dynamic reactive support following a critical double-circuit contingency involving either 500 kV lines between the Bruce complex and the SS.

Phase angle regulators (PARs) are installed on all four of the Ontario – Michigan interconnections. One PAR, on the Keith to Waterman 230 kV circuit J5D, has been in service and regulating since 1975. The other three available PARs, on the Lambton to St. Clair 230 kV (circuit L51D), the 345 kV circuit L4D and the Scott-Bunce Creek 230 kV (circuit B3N) remain idle. The operating agreements are ready. The completion of the filing process with FERC and the U.S. Department of Energy is in progress. Although they are currently bypassed, these PARs can be placed in service and operated to control flows during emergency conditions.

In October 2009, Ontario launched a feed-in tariff (FIT) program which generated strong interest in renewable generation. Proponents representing more than 17,000 MW of renewable generation have applied for connection under the FIT program as of May 2011. The existing transmission system has already accommodated over 3,500 MW of FIT contract offers. The contract offers include transmission- and distribution-connected projects. The remaining projects are awaiting further assessments.

The Government of Ontario's Long-Term Energy Plan, specifies five priority transmission projects to accommodate renewable generation, serve new load, and support reliability. Further in a Supply Mix Directive on February 17, 2011, the OPA was required to include the five priority projects in its Integrated Power System Plan (IPSP). The five priority transmission projects are:

- Device(s) to enhance transfer capability, such as series or static var compensation, or other similar devices, in Southwestern Ontario
- Upgrade existing line(s) west of London
- A new line west of London
- Enhance the East-West Tie along the east shore of Lake Superior through a new line
- New line to Pickle Lake

North-western Ontario (Northwest) is connected to the rest of the province by the double circuit 230 kV East-West Tie. The region has significant amounts of hydroelectric generation as well as other resources such as coal, gas, and biomass. A material portion of the coal phase-out program is occurring in this area, at Atikokan and Thunder Bay (a combined 500 MW). To maintain supply security in this area, over the wide range of possible system and water conditions, additional resources located in the Northwest or increased westbound transfer capability into this region through the East-West Tie are required. The conversion of Atikokan to biomass and Thunder Bay to gas operation, as indicated in the LTEP, can help address the near-term shortfall in resources to meet regional load. A longer term solution of East-West Tie enhancement can help maintain a reliable and cost-effective supply to the Northwest. The line is anticipated to be in service by 2017.

As one of the priority projects, a new supply line to Pickle Lake is currently being planned as part of a potential suite of options that may be required to serve growing load and maintain reliability in the system north of Dryden. Load in and north of this area is forecasted to grow from about 85 MW to about 185 MW by 2020 and it is expected that new supply to the area will be required beginning in the 2013-2015 timeframe. The new line to Pickle Lake will be either a single circuit 115 kV or a single circuit 230 kV line from either the Dryden area or the Ignace area. The 115 kV options will be approximately 230 km in length while the 230 kV options will be approximately 300 km in length. The 230 kV option will have the additional capability to support growth in the Red Lake area, provide operational flexibility to enable refurbishment of end-of-life equipment, and serve new load for mining operations in the area known as the Ring of Fire. The Ring of Fire area is approximately 350 km northeast of Pickle Lake. If the new supply line to Pickle Lake is delayed, load that is being planned for connection in 2014 and 2017 will not be able to connect until the new line is available.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering NGS. Pickering NGS units connect directly to the 230 kV system at Cherrywood TS in the east Greater Toronto Area. The retirement of Pickering NGS would require additional 230 kV supply source for the area. A new 500/230 kV transformer station in the Oshawa area which would provide 230 kV supply source to the area is one of the options under consideration.

As demand increases in the western part of the Greater Toronto Area, the loading on the 500/230 kV transformers at Claireville TS and Trafalgar TS will exceed their capacity by about the middle of this decade. An additional 500 to 230 kV supply source would be required to relieve the loading on the existing autotransformers. Installation of 500/230 kV transformers by 2016 at the 500 kV Milton Switching Station is one of the options under consideration.

The LTEP includes three transmission projects to accommodate additional renewable generation in southwestern Ontario – two upgrade projects, and one new transmission line project. The two upgrade projects consist of a reactive compensation project and a line re-conductoring project. For the reactive compensation project, different upgrade options under consideration include use of existing reactor switching schemes, installation of SVCs, and series compensation of 500 kV lines in southwestern Ontario. The two upgrade projects are intended to maximize the capability of the existing system and increase capability to incorporate additional renewable resources in a shorter timeframe than a new transmission line can be built. The planned in-service date for these upgrades is the end of 2014. A new transmission line west of London is targeted to be completed in 2017.

The transmission projects that are under various stages of construction and the planned projects will address the transmission constraints identified. The transmitters in Ontario together with the OPA proactively plan the transmission network in order to ensure timely system adjustments, upgrades, and expansions. Delays to the in-service dates of bulk transmission projects resulting from delays in obtaining required approvals or delays in construction may result in increased congestion or generation rejection in the interim.

For area supply adequacy and security, the OPA's integrated planning approach addresses project delays. Integrated planning develops options for each need, not in isolation but in a coordinated manner. Integrated planning is guided by principles that maintain a long-term view that anticipates uncertainties and maintains flexibility. Conservation, supply, and transmission plans are coordinated to deliver the options that are required. This includes regional balances of supply and demand as well.

The transmission lines east of Mississagi TS and the north-south corridor have experienced increased congestion due to the continuing addition of new renewable resources and the lack of transmission reinforcements. It is expected that congestion will further increase with projects in the area, both proposed and under construction, becoming operational. To help reduce this congestion and incorporate the future Lower Mattagami expansion projects and other renewable generation resources, Hydro One installed series compensation on the 500 kV north-south lines at Nobel SS and dynamic reactive compensation facilities at Porcupine TS. To further improve the north-south transfer capability Hydro One will install static reactive compensation facilities at Porcupine TS and Hanmer TS with a planned in-service date during the fourth quarter of 2011; dynamic reactive compensation facilities at Kirkland Lake TS with a planned in-service date during the second quarter of 2011; and static reactive compensation at Pinard TS with a planned in-service date during the third quarter of 2012. Additionally, the York Region load-serving capability will be reinforced with the addition of York Energy Centre, which is scheduled to go in service in the third quarter of 2012 to alleviate transmission constraints in the area.

Operational Issues

In the years following the 2014 coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. OPG will invest $300 million to ensure the continued safe and reliable performance of its Pickering B station for approximately 10-years to 2020. The feasibility of extending the operating life of the Pickering generating units is being studied and the government expects to have an update in 2012. At this time, Ontario will consider the possible conversion of some or all of the units at Nanticoke and Lambton to natural gas, if necessary for system reliability. Due to the lead times involved, planning and approval work for the natural gas pipeline infrastructure required to Nanticoke will begin soon. Units at Bruce B and Darlington are expected to reach the end of their service lives over the next decade. To extend the life of these units, these units will be out of service for about three years while being modernized.

Four coal units with the capacity of almost 2,000 MW were shut down in October of 2010. Two additional units at Nanticoke are expected to shut down by the end of 2011. All coal-fired plants in the province will be phased out by 2014. The Ontario Power Authority will negotiate a contract for biomass-fuelled generation from the Atikokan Generating Station. Two units at the Thunder Bay Generating Station are to be converted to run on natural gas over the period leading up to 2014.

The Government of Ontario's Long-Term Energy Plan is committed to continuing to use nuclear for about 50 percent of energy supply — this is equivalent to about 12,000 MW of capacity. Over the next 10 to 15 years, 10,000 MW of existing nuclear capacity will be refurbished. First and foremost, the focus will be on the improvement of existing assets so that those facilities can continue to provide reliable, affordable electricity. A coordinated refurbishment schedule has been prepared and is being regularly updated to reflect current information on resources and plant performance and conditions.

The remainder of the nuclear capacity that Ontario requires for its projected demand will be made up of new nuclear at Darlington (about 2,000 MW). OPG is continuing with two initiatives that were underway prior to the suspension of the new build procurement process: the environmental assessment and obtaining a site preparation license at Darlington.

Although energy supplies available within Ontario are expected to be adequate overall, energy deficiencies could arise periodically as a result of prolonged extreme weather conditions and environmental restrictions. Interconnection capability and available market and operational measures have been evaluated as adequate to ensure energy demands can be met for a wide variety of conditions. The IESO uses a measure of forecast uncertainty 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.

If peak demands are higher than expected, the IESO will invoke emergency operating state control actions which include recalling outages, voltage reduction, and emergency assistance from neighboring Reliability Coordinators.

Ontario is currently benefiting from improved resource adequacy levels, due to new supplies coming into service. *Future-Planned*, *Future-Other*, and *conceptual* supply resources and a lower demand forecast (due to Conservation targets, increased distributed generation, and a restructuring economy) has Ontario well positioned for the phase-out of approximately 4,500 MW of coal-fired generation by the end of 2014. This has enabled the Ontario government to implement greenhouse gas emissions targets for coal-powered generation – ensuring that between 2011 and 2014, annual emissions are two-thirds lower than 2003 levels.

The integration of variable resources (*i.e.,* wind, solar) is a major priority as Ontario moves towards a higher penetration of renewable resources. By 2018, renewable generation targets are 9,000 MW for hydroelectric generation and 10,700 MW for renewable resources other than hydroelectric (wind, solar, biomass). Similar to other jurisdictions, the IESO has identified that at higher wind penetration levels, heightened efforts by system operators will be required to ensure the system can accommodate the variability of wind generation. The IESO is in the process of implementing a centralized forecast system for wind resources directly connected to the IESO-controlled grid and for wind resources with an installed capacity of 5 MW or greater connected to a distribution system. This is expected to improve the accuracy of variable generation forecasts.

The expansion of renewable generation within Ontario's distribution systems is expected to increase significantly over the next seven years. It is expected that distributed generation will soon displace significant amounts of output from larger generating units that are connected to the high-voltage transmission system. These large units currently provide fast voltage control, operating reserve, and load following that contribute to the reliability of the grid. The IESO has been working with the OPA and Hydro One on the timely installation of targeted SVCs to replace this lost capability. Additionally the IESO is also assessing other operational issues and is actively engaged with stakeholders to develop the capabilities to maintain reliability of the grid, as the types and characteristics of the future supply mix changes. The IESO is also working with local distribution companies, the OPA and the Ontario Energy Board (OEB), the provincial regulator, and the generators to increase visibility of the real-time output of distributed generation in an effective manner.

Ontario is experiencing extended periods of Surplus Baseload Generation (SBG) over the spring, summer and fall months. SBG is an over-generation condition that occurs when electricity production from Ontario's base-load and intermittent facilities (nuclear, must-run hydroelectric, wind, etc.) exceeds demand. This typically occurs during the low-demand periods such as overnight, weekends and holidays. With expected increases to some types of base-load generation (*e.g.,* wind), and a lower forecast for demand, management of SBG conditions in Ontario is another significant priority for the IESO. Existing intermittent generators are not currently economically dispatched to assist with SBG management; their contracts permit them to inject energy when they choose. However, consultations are underway with grid-connected and large embedded intermittent generators to resolve SBG conditions. Generators under either type of contract can be curtailed for reliability reasons but new processes are under development to address future SBG conditions in a more efficient manner.

Demand measures currently comprise a total capacity of about 1,500 MW, which is over 4 percent of total resources. At these levels, any failure to respond to instructions from the IESO does not pose any significant concerns for reliability. Demand measures are grouped into two categories: price sensitive and voluntary. The IESO considers only price sensitive demand for adequacy assessment purposes and to be dispatched, they have to bid into the market like other resources.

Demand measures are expected to grow to about 2,300 MW over the next decade, representing about 6 percent of total resources. The IESO reviews all relay protection mis-operations and work with transmission operators to ensure that timely assessments and repairs are completed for reliable operation of the IESO-controlled grid.

Emerging and Standing Reliability Issues

This section contains this Assessment Area's Risk Assessment of Emerging Issues during the 2011-2021 Time Frame.

Impacts of Conservation, Energy Efficiency, Embedded Variable Generation and Demand Response in Load Forecasting Models

Demand forecasting continues to evolve and is becoming more complex due to a number of influencing factors. Conservation has had a significant impact on demand and continues to make it difficult for system planners and operators to capture or estimate the impact of Conservation programs and initiatives. Similarly, embedded generation is starting to require more attention from load forecasters as the amount of embedded generation capacity is expected to show a dramatic increase. The fact that much of the embedded generation will be variable in nature adds a new degree of volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system. Lastly, the evolution of the smart grid and smart grid technologies will unlock greater demand response and increase the complexity of operating the electricity grid.

The issue requires industry attention over the next 10-years. The consequence will be medium as the industry develops the means and processes to track and evaluate the individual programs' performance. Improved data collection and new models and tools will enable the industry to more accurately identify and assess the impacts of these initiatives on the power system.

Nuclear Development in the Aftermath of the Fukushima Accident

The future of nuclear generation has resurfaced after the nuclear accident that followed a massive earthquake and tsunami in Japan. Some countries are reviewing their nuclear energy policy while

Germany announced that it is shutting down its nuclear units by 2022. Japan, currently obtaining about 30 percent of its electricity from nuclear, has abandoned its plans to expand the use of nuclear energy in favour of renewables. Nuclear energy is an important part of the energy mix in many North American jurisdictions. In Ontario, about 50 percent of electrical energy is supplied by nuclear.

A number of initiatives are being taken worldwide after the accident. In Canada, for example, the Canadian Nuclear Safety Commission appointed a task force to examine lessons learned from the Japan accident. The task force will recommend short- and long-term measures to address any significant gaps at Canadian nuclear power plants, and determine whether any design modifications are needed. It will identify priorities for the implementation of corrective actions based on the lessons learned and the need, if any, for further study. CNSC also ordered all Canadian reactor operators to revisit their safety plans and report on potential improvements to be made.

Impacts of Resource Mix Changes on Operation and Transmission Infrastructure

Large amounts of renewable variable generation (primarily wind and solar) are going to be connected to the grid over the next five years. New nuclear units, which generally lack flexible economic dispatch, will be added to the mix in coming years. In Ontario, coal-fired generation will be phased out by 2014, resulting in the loss of significant load-following capability. As a result of these changes to the resource mix, load-following, frequency response and variable generation forecasting are issues the industry will have to manage. New procedures, mechanisms and tools will be developed to mitigate the impacts. The likelihood and consequences are rated medium throughout the period to reflect this eventuality.

Asset Renewal: A systematic approach for continuous modernization of aging energy infrastructure

Much of the current power system infrastructure, be it generation, transmission or distribution equipment, is aging and needs to be refurbished, replaced or upgraded to comply with new standards. A long-term strategy is needed to systematically plan and execute the infrastructure improvements in a coherent and coordinated manner to limit the effects and minimize the risks of taking resources out of service to do the work.

For example, in Ontario, the nuclear units at Bruce B and Darlington Generating Stations will reach their end of life in the next five to 10-years. Coal units will cease burning coal by 2014, with conversion to other fuels being considered as just one of several mitigating options. Some transmission components are over 80 years old and require upgrading. Although many companies have sustainment programs in place for asset renewal, the overall scope of the problem is what presents the challenge.

Ontario’s major power system renewal projects are due in the last five years of this decade, resulting in a five-year likelihood of medium and 10-year likelihood of high. The planning has started already, but implementation will be complex. Ontario’s regulatory framework has been evolving to address the challenges associated with infrastructure planning.

Smart Grid Technology and Smart Products

Ontario has made significant investments in the smart grid including the installation of more than 4.5 million smart meters. The development of smart grid technologies and products, in particular at the distribution level, continues to be monitored and adapted to Ontario's planning process. The development and installation of the Advanced Metering Infrastructure is starting to produce tangible gains such as reduced costs for metering and for service connections/disconnections as well as improved detection, isolation and restoration times associated with power outages. Smart grid technologies are already adding another layer of visibility into the condition and operation of the grid while also adding a layer of reliability by enhancing predictive capabilities regarding potential instabilities.

Historically, demand patterns and consumption habits have been well established and well known. This data has helped control room operators prepare for what are normally large – but predictable – ramps in either direction. With the introduction of smart grid technology and smart products, not to mention variable generation, these habits and profiles will change. This will be an issue moving forward because unanticipated changes to the demand profile may make it difficult to accurately predict demand which, in turn, could lead to challenges balancing the system.

Representative System Models

Managing the impacts of a contingency on the system and determining the future infrastructure required to maintain reliability on the system requires a model that accurately represents the local system and, to the extent possible, the entire interconnection. Inaccurate representations of system models in the simulation of steady-state, short-circuit and dynamic studies could lead to misleading results and reduced levels of reliability. The improvement of system models will be required to reliably integrate the changing resource mix.

Assessment Area Description

The Independent Electricity System Operator (IESO) is the Reliability Coordinator for the province of Ontario. The IESO manages the wholesale electricity market and oversees the reliable operation of the provincial electricity grid.

The province of Ontario covers an area of 1,000,000 square kilometres (415,000 square miles) with a population of 13 million. The single Balancing Authority in Ontario, the Independent Electricity System Operator (IESO) directs the operations of the IESO-controlled grid (ICG) and administers the electricity market. The Ontario Power Authority (OPA) is responsible for planning Conservation, renewables and other generation, and transmission development in Ontario. The ICG experiences its peak demand during the summer, although winter peaks still remain strong.

NPCC-Québec

Introduction

The Québec subregion is one of the five Reliability Coordinators within NPCC. Hydro-Québec, the main utility in the province of Québec, is a major contributor to the Québec electricity market. Hydro-Québec generates, transmits and distributes most of the subregion's electricity. In large part, it uses renewable generating options such as hydro power, and is now integrating wind energy as a logical complement to hydro power, through purchases from Independent Power Producers. Hydro-Québec takes an active interest in other renewable resources such as biomass, geothermal and solar energy. Additionally, Hydro-Québec contributes to research on new generation options, such as hydrokinetic power, salinity gradient power and deep geothermal resources. It also conducts research in energy-related fields such as Energy Efficiency.

The Total Internal Demand forecast for the 2011-2021 assessment period is slightly different last year's 2010-2019 forecast. The compound average annual growth is about 0.89 percent over the long-term assessment period. Capacity resources for the 2011/2012 winter season total 43,851 MW, of which 39,190 MW is categorized as *Existing-Certain*. A portion of installed wind capacity is under contract with Hydro-Québec Production (HQP) and is derated by 100 percent, as it has been in earlier assessments. Other wind generation sites are under-contract with Hydro-Québec Distribution (HQD) with peak capacity amounting to approximately 30 percent of nameplate capacity. The refurbishment of the Gentilly-2 nuclear generating station (675 MW) will span between 2012 and 2014 and is projected to return to service for the 2014/2015 winter season. The Tracy plant (450 MW) has been mothballed.

The most recent Québec Balancing Authority Area Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on November 30, 2010, indicated that the Reserve Margin for reliability criterion compliance (expressed as a percentage of the Total Load Forecast) should be approximately 10 and 12 percent for short- and long-term assessments, respectively. When compared to other NPCC subregions, the Reserve Margin for Québec is lower than other because hydro plants with multi-annual reservoirs have inherently higher availability. Accordingly, Québec's Anticipated Capacity Resources Reserve Margin varies between 12.5 and 14.9 percent, remaining above the target Reserve Margin throughout the assessment period.

A total of A total of 891 miles of planned transmission lines are expected to come into service between 2011 and 2021, with an additional 232 circuit miles currently under construction. There are no transmission reliability concerns identified for the Québec subregion. 4,495 MW of additional capacity resources are also expected to come on line during the assessment period, including 2,666 MW of wind generation and 196 MW of biomass.

Reliability Assessment

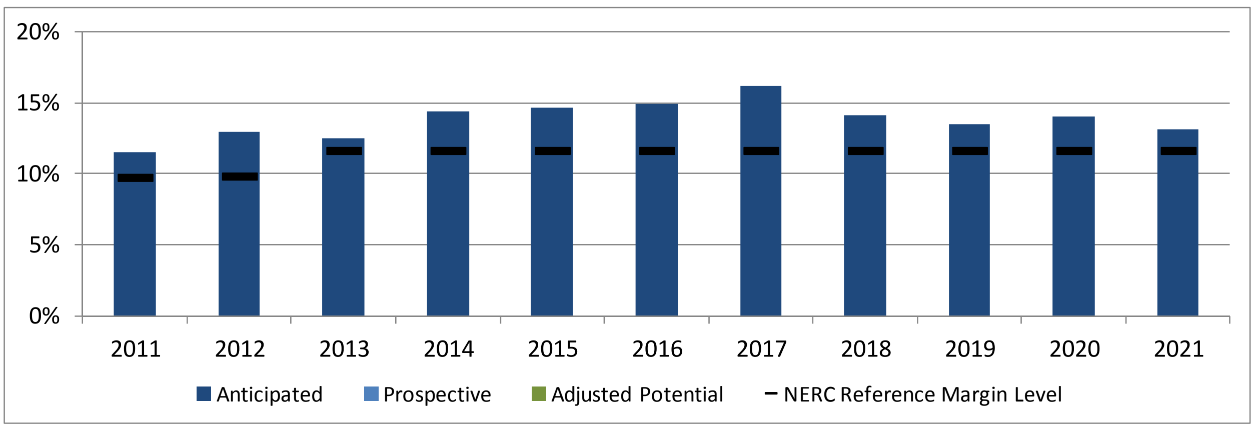
Resource adequacy is assessed in the Québec subregion by applying a Loss of Load Expectation (LOLE) criterion of 1 day in 10-years (represented by an hourly load system). This criterion complies with the Resource Adequacy Criterion included in the NPCC Reliability Reference Directory #1 – "Design and Operation of the Bulk Power System." The latest resource adequacy study is described in the 2010

Québec Interim Review of Resource Adequacy. This study shows that Québec meets the NPCC Resource Adequacy Criterion under the base case scenario of peak load forecast for the entire period covered by the Interim Review (2011-2013).

The mothballing of the Tracy generating station and the refurbishment of the Gentilly-2 nuclear generating station are largely offset by additional hydro, wind and biomass resources projected to come online during the period of this assessment.

The Québec subregion has sufficient resources to meet its Reserve Margin requirement for each year of the assessment (Figure 103.); however, in the event of an emergency situation, the subregion can call on additional resources from its neighboring NPCC subregions – New York ISO and Ontario (IESO). The Anticipated Resources Reserve Margin ranges between 11.5 and 16.2 percent throughout the assessment period.

Figure 103: Annual On-Peak Winter Planning Reserve Margins



The short-term (1-4 years) and long-term (5+ years) Reserve Margin requirements are treated slightly differently by the Québec subregion. While long-term required reserves are set equal to the fourth year of the assessment, the four-year time frame allows sufficient time to build new peaking units or find additional demand-side management (DSM) resources.

Most of Québec's generating resources are hydro facilities, with fossil-fuel generation typically used for peaking purposes, accounting for less than two percent of total capacity. The hydro generation system consists of multi-annual and annual reservoir generating plants, as well as run-of-river plants. Hydro plants with multi-annual storage facilities represent over half of the installed hydro capacity. In the event of a severe drought (2 percent probability of occurrence), the system's hydro generation capabilities would suffer hydraulic restrictions of about 500 MW, in addition to "normal condition" restrictions. Stream flow, storage level, and snow cover are constantly monitored to allow for adequate planning measures to manage the impacts of a potential drought.

The following mitigation strategies have been proposed to smooth-out the impacts of low inflow cycles:

- Reducing energy stock in reservoirs annually (in May) to a minimum of 10 TWh
- Reducing external non-firm energy sales

- Using thermal generating units for an extended time period
- Using off-peak purchases from neighboring areas

The transmission planning processes in Québec are structured to limit transmission constraints. However, under particular circumstances, wind plants located in the Gaspésie peninsula are vulnerable to transmission limitations, but are not projected to occur during periods of peak demand.

The Québec Assessment Area has no Renewable Portfolio Standards; however, the Québec Government has established certain targets for renewable resources. Specific calls for tenders have been launched by HQD in order to meet these targets. If additional resources are necessary for resource adequacy purposes, HQD will assume responsibility for driving the procurement process, which will be open to all resources.

For resource adequacy assessments, a wind capacity credit is based on 30 percent of the nameplate capacity, as shown in the 2009 Interim Review of Resource Adequacy. Over 35 years of meteorological data, between 1971 and 2006, were used to re-simulate load and wind generation with an hourly time step. This dataset was used along with conventional generation data in two different models: the Multi-Area Reliability Simulation (MARS), and the FEPMC, a Monte-Carlo model developed by Hydro-Québec. The results from both models indicate the appropriateness of using a 30 percent wind contribution during winter seasons. Since this result considers only wind plants under contract with HQD, all other wind capacity in the control area was completely de-rated. Wind resources in Québec are also completely derated during the summer seasons. Two types of Demand Response programs are used in the Québec Assessment Area. One type consists of two interruptible load programs and the other consists of a voltage reduction scheme. The two interruptible load programs total 1,350 MW. One is de-rated by 15 percent and the other by 30 percent depending on each program's features with regard to the system's operating flexibility. The voltage reduction scheme, extensively tested by TransÉnergie (Québec's Transmission Operator), has an load-reduction impact of approximately 250 MW.

The Gentilly-2 nuclear plant (675 MW) announced refurbishment activities that will commence in 2012 and continue until 2014. The Tracy unit retirement (450 MW fossil fuel) is not projected to impact reliability. The loss of these resources will be offset by *Future-Planned* generation units (hydro, wind and biomass), which are projected to come on-line during this assessment period.

A total of 2,500 MW of Under-Voltage Load Shedding (UVLS) will be available in the Québec subregion during this assessment period. These devices have been designed to operate following contingencies involving the loss of two or more 735 kV transmission lines in the system. These contingencies do not require more than 1,500 MW of load shedding, although UVLS operates on a pre-defined pool of 2,500 MW (located in the Montréal area). The NPCC Comprehensive Review Assessment of the Québec Transmission System for 2012 (the last Comprehensive Review to date) conducted by Hydro-Québec TransÉnergie (acting as Transmission Planner) shows that UVLS is adequate to preserve system stability after the extreme contingencies for which it is designed. No additional load is expected to be assigned to UVLS through 2021. Additionally, Special Protection Systems or Remedial Action Schemes are not projected to be installed in lieu of planned bulk power transmission facilities in the Québec subregion.

TransÉnergie, as transmission planner, performs formal system planning studies, as well as impact studies for generation, load and interconnection integration (including NPCC's Comprehensive Review Assessments). These studies and assessments are conducted in response to NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" and according to NERC TPL standards.

The planning study entitled "Transmission System reinforcement for Year 2011" (a large scale study of the 735 kV system to cover all impacting changes on the system through 2012) identified a number of operating limitations due to reactive power supply and the integration of the new 1,250 MW interconnection with Ontario. To ensure system stability for these events, a number of solutions have been recommended, most notably, the need for additional reactive power sources.

Other impact studies for the integration of generation on the system are also performed by TransÉnergie. For example, a study titled "Transmission System Study for the Integration of Fifteen Wind generation sites from Call for Tenders #2005-03" recommends a transmission system upgrade scenario to integrate 2,000 MW of wind generation through 2015.

The filing to the Régie de l'énergie du Québec (Québec Energy Board) for wind generation integration includes shunt capacitor additions, series compensation additions, Static Var Compensator (SVC) additions, nominal current upgrades in existing series compensation and various protection projects. These projects have been approved by the Québec Energy Board.

Finally, the next hydroelectric generation project, the Romaine Complex is expected to come online between 2014 and 2020 on the Lower North Shore of the St. Lawrence River. This project consists of four generating stations, totaling 1,550 MW. Studies have been ongoing to determine 735 kV upgrades needed for the project and a filing was presented to the Québec Energy Board on March 2, 2011. The addition of a 735 kV transmission line will be required, along with a switching station on the Manicouagan-Québec sub-system to integrate the Romaine Complex through 2020. These studies will attempt to alleviate the dynamic and static voltage support on the 735 kV system. Regional integration studies mostly focus on local overload problems occurring as a result of added capacity in each regional subsystem.

TransÉnergie has a criterion for minimum dynamic reactive requirements. Due to system geography and configuration, generation centers are remote from load centers, requiring long 735 kV lines, which impacts synchronous condensers and Static VAr Compensators (SVCs) distributed throughout the system. There are presently 21 SVC and synchronous condensers on the system, each with a nominal reactive power range of -100 to +300 MVAR. The steady state operating range is -50 to +50 MVAR per compensator, so that a 250 MVAR margin per compensator is available as dynamic reactive reserve (up to 5,300 MVAR total). Two new -300/+300 MVAR SVCs are projected to come into service for the 2011-2012 winter season. Several 330 and 165 MVAR reactors on the 735 kV lines may be switched on and off the system to remain within the operating rande of the compensators. The SVC and synchronous condenser operating range is strictly monitored during operations in order to maintain the dynamic margin.

TransÉnergie's system consists of an extensive 735 kV network with an underlying 315 kV, 230 kV and 120 kV subsystems totaling close to 21,000 circuit miles. The system uses (and will continue to use) telecommunications and advanced protection and control applications to ensure reliability and improve performance. The system is maintained in accordance to NPCC and NERC Planning Standards, but with additional criteria that consider system topology and substation characteristics particular to TransÉnergie's system. Special Protection Systems (SPSs) will continue to be used in to ensure reliability in response to extreme events.

Other tools and technologies will also be used to enhance bulk power system reliability and are listed below:

- A planning criterion for voltage sensitivity
- Synchronous condensers, Static VAr Compensators, Variable Frequency transformers
- Series compensation
- Multi-band power system stabilizers
- Advanced simulation tools (Voltage stability assessment, among others)
- Digital relaying
- New maintenance schedules and technologies to address equipment ageing and sustainability
- Inertial emulation of wind turbines to provide reserve
- HVDC technological reviews and eventual upgrades

Currently, Smart Grid programs have not been fully implemented at Hydro-Québec, however, the IMAGINE project is still underway. IMAGINE involves automated maintenance and enhanced processing of monitoring data. Altogether, 55 substations are now connected to two remote maintenance centers in Montréal and the city of Québec. This project, which focuses first and foremost on power transformers, will enable TransÉnergie to optimize target maintenance efforts to prevent equipment failures and improve system reliability. The IMAGINE investment is over and above the budget for initiatives also carried out with IREQ, Hydro-Québec's research center, with the help of industrial partners.

TransÉnergie is also working with IREQ to prepare a smarter transmission grid of the future. In 2010, the outline for an adaptive power grid was proposed. Specifically, controllers, sensors, analysis systems and other devices would be used to continuously monitor equipment and manage system components in real-time. Related projects include the ACOR grid response improvement program, designed to increase overall system capacity, reliability and security by means of advanced protections and controls.

Presently, there are no project slow-downs, deferrals, or cancellations projected to impact reliability in the Québec subregion.

Demand

The 2011/12 winter peak Total Internal Demand forecast for Québec is 37,153 MW, increasing to 40,968 MW by 2021, with an average annual growth rate of 0.89 percent (Table 95).

Table 95: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	37,153	40,968	3,815	0.89%	10.3%
Net Internal	35,553	39,868	4,315	1.05%	12.1%

Hydro-Québec Distribution (HQD) is the only Load Serving Entity (LSE) in the Québec subregion. Thus, the load forecast is conducted for the Québec Balancing Authority Area, represented as a single entity, negating any need for demand aggregation. Resource evaluations are based on coincident winter peak forecasts, with base case and high case scenarios.

The load forecast was prepared using end-use models for different electricity consumption sectors, combined with data gathered through customer surveys, economic, demographics and technological assessments, as well as other factors that impact electricity use. Economic conditions are cautions as slow recovery continues with many industrial sector still experiencing difficulties.

The Québec peak load forecast is based on 35-year average temperatures (1971-2006), adjusted for a global warning effect of 0.30°C (0.54°F) per decade starting in 1971.Each year of historical climatic data is adjusted ±3 days to gain information on conditions that occurred during either a weekend or a week day. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of the peak hour for each scenario.

Load forecasts have incorporated expected reductions in peak demand to be achieved by Hydro-Québec Energy Efficiency programs. HQD's goal for recurring energy savings in 2012 is 8.8 TWh, increasing to 25.3 TWh in 2021. These projections will be achieved primarily through Energy Efficiency Plans (EEP) to reach 17 TWh by 2021. Existing Energy Efficiency trends in the demand forecast models (including programs that were origionally, implemented by Hydro-Québec during the 1990s) will also contribute.

The EEP focuses on energy Conservation measures with programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. These programs encourage Conservation of Energy Star appliances, lightning and refrigerators, increased recycling activities, management of electric power for large industry, as well as programs catered toward industrial users.

The projected impact of these programs is incorporated in the load forecast of this assessment. In terms of capacity, the expected impact of these programs reduction of on-peak demand for 2011/12 is 1,530 MW, growing to approximately 3,650 MW in 2021/22. Detailed information on programs features can be found on Hydro-Québec's website.

As mentioned above, there is no Renewable Portfolio Standards (RPS) in Québec; however, some Demand Side Management (DSM) targets have been proposed by the Québec Government. Accordingly, Hydro-Québec Distribution must to file monitoring reports to the Québec Energy Board in relation to these targets.

As mentioned in the Reliability section of this report, the Québec subregion has two types of Demand Response Programs totaling 1,600 MW specifically designed for peak-shaving during winter operating periods:

- Interruptible demand programs (mainly addressed to large industrial customers) have an impact of 1,350 MW on-peak demand.
- A voltage reduction scheme with 250 MW of demand reduction at peak.

Current projections indicate that the total DSM will contribute slightly less in 2021 (Table 96).

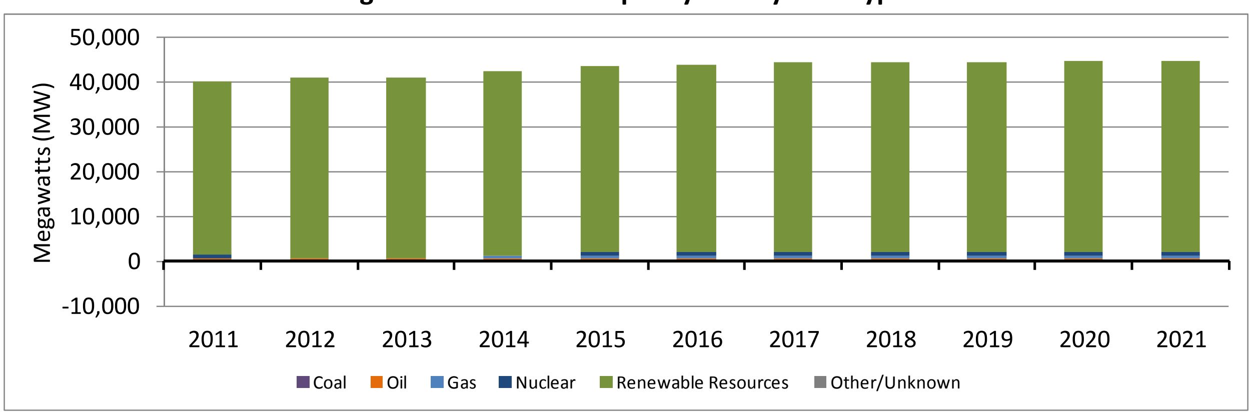
Table 96: Winter On-Peak Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	-	-	-
Non-Controllable Demand-Side Management	-	-	-
Direct Control Load Management	250	250	-
Contractually Interruptible (Curtailable)	1,350	850	(500)
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**1,600**	**1,100**	**(500)**
Total Demand-Side Management	**1,600**	**1,100**	**(500)**

Generation

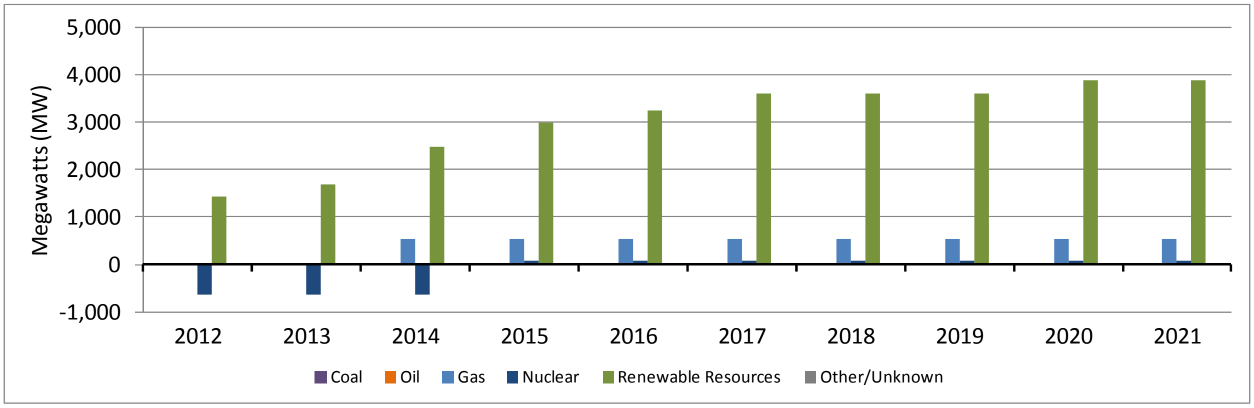
Most of Québec's generating resources are hydro facilities. Some coal and gas generation is also used for peaking purposes, accounting for less than two percent of total capacity (Figure 104).

Figure 104: On-Peak Capacity Mix by Fuel Type



As discussed in the Resource Adequacy section, the Gentilly-2 nuclear plant (675 MW) announced refurbishment activities to commence before 2012 and continue until 2014. Hydro-Québec is also adding renewable resources, including biomass, geothermal and solar energy. Finally, the next hydroelectric generation project, the Romaine Complex is expected to come online between 2014 and 2020 on the Lower North Shore of the St. Lawrence River. This project consists of four generating stations, totaling 1,550 MW (Figure 105).

Figure 105: Annual Net Capacity Change by Fuel Type



Plans for additional resources over the assessment period are primarily renewables, including hydro, wind and biomass resources. Large hydro plants are presently under construction (Romaine Complex) and represent the most important part of the new effective capacity additions. Smaller hydro plants, as well as some biomass and wind resources are assessed based on contractual agreements between HQD and Independent Private Producers (IPP).

Wind capacity forecasts are modeled using long historical data series. Results of the study were presented to the Québec Energy Board and the NPCC. This study indicated that the actual wind plant capacity and contribution to Loss of Load Expectation was equal to 30 percent of nameplate capacity. This first effective wind capacity calculation was based on the expected geographic dispersion of 3,000 MW of wind plants.

Biomass resources currently amount to 164 MW of *Existing-Certain* capacity in 2011, with an additional 52 MW of on-peak capacity planned to come online by 2021 (Table 97).

Table 97: On-Peak Expected and Derated Renewable Resources

	Renewable Resource	2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	141	941	800
	Derated	541	2,407	1,866
	Wind - Total Nameplate Capacity	**681**	**3,348**	**2,666**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	37,543	40,585	3,042
	Derated	1,475	1,475	-
	Hydro - Total Nameplate Capacity	**39,018**	**42,060**	**3,042**
Biomass	Expected	164	216	52
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**164**	**216**	**52**

Conceptual resources are not modeled. Furthermore, distributed generation and behind-the-meter generation are not considered in this assessment.

Capacity Transactions

Expected capacity purchases are planned by Hydro-Québec Distribution for its own needs (Québec internal demand). These purchases will show up during peak periods only: for the 2011/12 peak period they will amount to about 100 MW. The long-term assessment shows a need for about 1,100 MW during peak periods. These purchases may be supplied by resources located in Québec or in neighboring markets. In this regard, HQD has designated Massena – Châteauguay (1,000 MW) and Dennison – Langlois (100 MW) interconnections transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by firm long-term contracts. However, on a yearly basis, HQD proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed.

For the period from June through September 2011, there are firm capacity sales to New England, New York and Ontario totaling 1,661 MW. Moreover, during the same period there is an expected firm capacity sale of 421 MW to New York.

After 2011 and for the period of this assessment, the Québec subregion will support firm capacity sales totaling 455 MW to New England and Ontario (Cornwall). These are backed by firm contracts for both generation and transmission. These firm capacity sales will continuously decline to 151 MW in 2021. Finally, during summer periods from 2012 to 2021, there will be additional expected capacity sales of 1,574 MW in 2012, 1,521 MW in 2013 and 1,866 MW from 2014 to 2021 (Table 98).

Table 98: On-Peak Capacity Transactions

Transaction Type		Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	-	-	90	1,100
	Expected	-	-	90	1,100
	Provisional	-	-	-	-
	Total	**-**	**-**	**180**	**2,200**
Exports	Firm	1,661	-	455	151
	Expected	-	1,866	-	-
	Provisional	-	-	-	-
	Total	**1,661**	**1,866**	**455**	**151**
	Net Transactions	**(1,661)**	**(1,866)**	**(275)**	**2,049**

Transmission

This section briefly describes the bulk power system transmission additions anticipated in-service during the 2011/2021 study period of this report.

Eastmain-1-A – La Sarcelle Hydro Project[268]

Presently, the Eastmain-1-A (768 MW) and the La Sarcelle (150 MW) hydro generation stations are in the commissioning phase along with the accompanying transmission. TransÉnergie, the Transmission

[268] http://www.hydroquebec.com/rupert/en/index.html.

Planner, has commissioned the Eastmain-1-A – Eastmain-1 (1.0 km) double-circuit line and the La Sarcelle – Eastmain-1 (102.1 km) 315 kV single-circuit line in 2011. These lines complete the La Sarcelle – Eastmain-1 – Eastmain-1-A generation complex integration into the main grid at Némiscau T.S. (James Bay sub-system).

Romaine River Hydro Complex

Hydro-Québec Production (HQP) is now constructing the Romaine River Complex on the Lower North Shore of the St. Lawrence River. The Romaine River discharges into the St. Lawrence River near the town of Havre-Saint-Pierre. This generating complex is made up of four generating stations totaling 1,550 MW. TransÉnergie is now in the planning stage for the integration of this project to the system. The Generating Stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 (645 MW) and Romaine-1 (270 MW) will be integrated in 2014 - 2016 at Arnaud 735/315 kV substation. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated in 2017 - 2020 at Montagnais 735/315 kV substation.[269]

The Romaine Transmission Project has been filed with the Québec Energy Board on March 2, 2011 and subsequent hearings will held.[270]

Main system upgrades for this project require construction in 2014 of a new 735 kV switching station to be named “Aux Outardes” and located between existing Micoua and Manicouagan T.S. Two 735 kV lines will be redirected into the new station and one new 735 kV line (5 km or 3 miles) will be built between Aux Outardes and Micoua.

Other work required on the main system is:

- New series compensation at Jacques-Cartier (Line 7018) and Duvernay (Line 7002) stations
- Existing series compensation upgrades at Arnaud station
- Capacitor bank additions at Saguenay 161 kV station
- Two 735 kV, 330 MVAr shunt reactor additions (Laurentides, Appalaches)
- Line protection modifications at several 735 kV stations
- Communications network extensions

These main system upgrades are required to maintain conformance to Planning Standards with the new Romaine generation on the grid.

Wind Integration Projects

Different calls for tenders for wind generation have been issued by Hydro-Québec Distribution in the past years. A total of approximately 3,348 MW (Including wind generation already in service) is forecasted to be on line in 2015. A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages to integrate this wind generation.

[269] http://www.hydroquebec.com/romaine/index.html.

[270] http://internet.regie-energie.qc.ca/Depot/WebPages/ProjectPhaseDetail.aspx?ProjectID=98&phase=1.

These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspesia Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

All system additions and modifications have been filed with the Québec Energy Board on August 17, 2010. Hearings were held on this project and it was approved on December 23, 2010.

These include transmission additions to be made on the main system, such as series compensation additions at Chénier (Line 7044), Grand-Brûlé (Line 7045) and Duvernay (Line 7016) 735 kV stations. The project also includes the addition of an SVC at Bout-de-l'Île substation after the addition of a 735 kV section at Bout-de-l'Île and an SVC at Jacques-Cartier substation. Nominal current upgrades will also be done on existing series compensation at La Vérendrye, Abitibi and Duvernay. A thermal capacity upgrade will be done on the two Lévis – Nicolet 735 kV lines and several protection and communications modifications are also scheduled to finalize this project in 2016.

System Reinforcement Project

A System Reinforcement Project submitted to and approved by the Québec Energy Board du Québec is still ongoing. Mainly, this includes two Static Var Compensators (SVCs) to be installed at Chénier 735 kV substation and series compensation on two 735 kV lines (The two Chamouchouane – Jacques-Cartier lines). The two SVCs and series compensation are now under construction and will be commissioned for the 2011-2012 peak load period. Moreover, the Board has also approved the addition of two 200 MVAr inductive branches on the Chénier SVCs. This is to account for the filing of the 2 X 1,200 MW firm point to point transmission service by Hydro-Québec Production on the HQT-MASS and HQT-NE interconnections using the Châteauguay and Phase II interconnections. The project also includes Bergeronnes series compensation nominal current-carrying capacity upgrade in 2014. Finally, a third 345 MVAr 315 kV shunt capacitor bank is now under construction at Duvernay substation and will be in service by the end of 2011.

Chamouchouane – Montréal 735 kV Line

The large generation additions and transmission services coming up over the next years require, as shown above, a number of system additions to maintain reliability. Moreover, planning studies have shown that to optimize the different solutions and to significantly reduce marginal losses on the system due to this new generation, a new 735 kV line from Chamouchouane to Montréal (about 370 km or 230 miles) is required around 2017. This optimization will result in regrouping some of the above-mentioned projects and in other cases, will result in reducing additional equipment that was previously planned. The new line will also reduce transfers on other parallel lines on the Manicouagan – Québec Interface, thus optimizing operations flexibility.

Public information meetings have begun on this project. Final line route and destination in Montréal has not been determined yet and government authorization processes are ongoing.

Regional Projects

In 2013, the 735 kV section addition at Bout-de-l'Île (East end of Montréal Island) substation also includes the addition of two 735/315 kV, 1,650 MVA transformers. The new 735-kV source will permit redistribution of load around the Greater Montréal area and will absorb load growth in the eastern part of Montréal. This project will enable major modifications to the Montréal area regional sub-system. Many of the present 120 kV distribution stations will be rebuilt into 315 kV stations and the regional network will be converted to 315 kV (Vimont, Bélanger, Blainville, Fleury, de Lorimier substations).

Other regional projects will continue in the Québec City area (Limoilou, Lefrançois and Charlesbourg projects), in the Beauceville area, and in the Mauricie – Montréal 315 kV corridor (Pierre-Le Gardeur 315/120 kV, Lachenaie and Lanaudière projects).

Reliability-Related Projects

TransÉnergie's transmission planning studies and generation/load integration studies are conducted according to NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System", and according to NERC TPL standards. Due to TransÉnergie's particular system configuration and to the fact that the system is a separate Interconnection in North America, system planning is conducted such that no transmission constraints or congestion are forecasted to appear on the system. Moreover, TransÉnergie has chosen to design its system to withstand other contingencies otherwise considered extreme by NPCC. The system's particular topology — long 735 kV branches connecting remote generation centers with load centers concentrated in the southern part — imposes a particular treatment for these contingencies. Even though their severity is comparable to that of extreme events, their probability of occurrence — because of the bus arrangement — is such that a performance level close to what is required for transmission design contingencies is required here. Thus, TransÉnergie considers these "complementary" contingencies in its system design. When assessing complementary contingencies, use of limited generation rejection is allowed to ensure system transient stability but service continuity is privileged so that only a limited amount of under-voltage load shedding for the worst contingencies is allowed.

The 735 kV system upgrades and additions mentioned above are necessary to maintain system reliability after the hydro and wind projects have been integrated to the grid. Moreover, two new firm point to point transmission services have been filed with TransÉnergie by HQP. Internal system demand will grow at an approximately 1.0 percent yearly rate. Transfers on the 735 kV interfaces will be higher with time. System studies have shown that in some cases, transmission design contingencies or complementary contingencies will lead to system instability and that these projects must be completed so that the system remains in conformance to TransÉnergie's Planning Criteria.

Presently, the projects that have been filed with the Québec Energy Board have all been approved after no or very little modification. Future projects are expected to be filed in due time. No delay is presently forecasted concerning the more important bulk power system projects. Mitigation measures such as transfer limitations, temporary use of SPSs, etc. will be considered in due time, if a particular project suffers delays. These measures will be planned so as to ensure reliability of the bulk power system while finalizing the project.

Hydro-Québec TransÉnergie does not foresee any transmission constraints during this assessment's horizon that could significantly impact reliability. Due to TransÉnergie's particular system configuration and to the fact that the system is a separate Interconnection in North America, system planning is conducted such that no transmission constraints or congestion are forecasted to appear on the system.

Operational Issues

Hydro-Québec maintains an ongoing emergency plan in case of catastrophic events. This stems from a number of Federal and provincial legislation, rules, procedures and municipal by-laws. At the corporate level the plan includes objectives, risks, the committee structure, and communications.

This plan covers a large array of situations, for example: the potential rupturing of a dam, a nuclear incident, extensive damage to transmission,, forest fires, unavailability of computer or telecommunication systems, biological risks, cyber security,, terrorism, or other risks to the system. Hydro-Québec's emergency plan also provides links with the Québec Civil Security Organization and other civil, military, or medical organizations and directs Hydro-Québec's divisions to elaborate and maintain individual sector plans, according to threats specific to each area.

Hydro-Québec's intranet website has several web pages pertaining to this emergency plan where employees can access information and arrange training.

Québec's planning process involves four high level concepts, namely prevention, readiness, post-event intervention and restoration. These concepts include consideration for communications procedures, personnel training, on-site exercises and follow-up evaluation. Management is responsible for ensuring that the planning process is implemented at all times and a specific team has been designated to review all related documentation to verify that all material is updated and posted.

The planning process for catastrophic events completes system planning as required by NPCC's Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" and by NERC's Transmission Planning Standards TPL-001 to TPL-004. These standards define a number of system events that must be assessed under specified conditions. For NPCC, an Extreme Contingency Assessment includes the following examples:

- Loss of the entire capability of a generating station
- Loss of all transmission circuits in a common right-of-way
- The sudden dropping of a large load or major load center
- The sudden loss of fuel delivery systems to multiple plants

A similar NERC Standard (TPL-004) exists to minimize impacts on the system. Specifically, Special Protection Systems (SPS) may be used following extreme contingencies.

In the case of an extreme contingency leading to a system blackout, automatic devices called SPSR (French acronym for "System Separation Solution") act locally at a number of 735 kV stations to close-in sacrificial Zinc Oxide surge arrestors before the system dismantles. The surge arrestors are calibrated to conduct and cause a controlled dismantlement of the system in order to avoid over voltage situation that could damage equipment. This minimizes system restoration time and maximizes equipment availability following a blackout. These surge arrestors would need to be replaced after such an event. No system outages are projected during the 2011-2021 assessment period.

The voltage-dip criteria applicable to the bulk power system guidelines after a system contingency are shown below (Table 99).

Table 99: Voltage Limits on the Transmission System

Nominal Voltage	Normal Limits				Emergency Limits			
	Low		High		Low		High	
(kV)	(kV)	(p.u.)	(kV)	(p.u.)	(kV)	(p.u.)	(kV)	(p.u.)
735 kV	725	0.985	760	1.030	698	0.950	765	1.040
315 kV	299	0.950	331	1.050	284	0.900	347	1.100
230 kV	219	0.950	242	1.050	207	0.900	253	1.100
Interconnections	N/A	0.950	N/A	1.050	N/A	0.900	N/A	1.050

The emergency limits must be met within five minutes of a contingency, through the existence of automatic voltage regulation devices with the adequate amount of reactive capacity built into the system. The 735 kV Emergency Low Limit is stringent and the use of MAIS (French acronym for Automatic Shunt Reactor Switching System) is authorized only after an attempt to re-establish 735 kV voltages. The transient limit is 0.80 p.u. voltage for two seconds after fault clearing and the mid-term limit is set at 0.90 p.u. from two seconds, up to five minutes after fault clearing. All transient and long-term voltage stability analyses must adhere to these criteria.

Hydro-Québec intends to deploy a number of new technologies, systems and tools to improve future bulk power system reliability.. The Smart Grid is the most notable and governmental policies and targets for renewable energy integration, Energy Efficiency, electric or rechargeable hybrid vehicles and greenhouse gas emission reductions are among the major drivers. Additional future challenges include:

- Integrating renewable energy generation of various types, outputs and locations.
- Increasing exchanges between networks.
- Predicting and controlling load and supply variations and preparing for the more widespread use of rechargeable hybrid and all-electric vehicles.
- Ensuring optimal integration of the various technologies involved in the smart grid.
- Reducing maintenance costs and optimizing replacement costs.

Hydro-Québec's generating units are primarily located on different river systems throughout the province. The major plants are backed by multiannual reservoirs (water reserves lasting at least one year). The Québec Balancing Authority Area can rely on those multi-year reservoirs and on other non-hydraulic sources, such as fossil generation, allowing it to cope with inflow variations.

Hydro-Québec has developed energy criteria to ensure the availability of sufficient resources to run through sequences of two-year or four-years reduced inflow levels. Hydro-Québec must demonstrate its ability to meet this criterion three times each year to the Québec Energy Board.

Two plants are out of service in this assessment. Tracy thermal plant (600 MW) is assumed to be out of service over the period of this study. Gentilly 2 nuclear station (675 MW) will be refurbished through the period 2012-2014. The plant is expected to come back in service for the 2014/15 winter period. The 547 MW natural gas unit operated by TransCanada Energy (TCE) at Bécancour (under contract with HQD) is also scheduled out of service due to a lack of load demand.

Operational planning studies are being continuously conducted by TransÉnergie, the Québec controller. Yearly peak demand period studies are conducted to assess system conditions during winter peak periods. Extreme weather in Québec with very low temperatures translates to high demand during winter operating periods. Through a transmission planning criterion, transmission planning studies must take into account a 4,000 MW load increase above the normal load forecast for the system during such extreme weather conditions. This is equivalent to 111 percent of system peak load. The subregion relies on both internal and external resources to serve additional load and transmission capacity is based on existing planning criteria.

HQD, as the only LSE in Québec, develops annual procurement resource plans, submitted to the Québec Energy Board for hearings, review, and ultimate approval. Procurement plans include low, medium and high case forecast scenarios.

Transient and voltage stability operating studies are performed continuously by TransÉnergie to establish system operating transfer limits on all possible system configurations.

If peak demands are higher than expected, a number of measures are available to system control personnel. Operating Instruction I-001 lists these measures, which are listed below:

- Limitations on non-guaranteed wheel through and export transactions
- Operation of hydro generating units at their maximum output (away from optimal efficiency)
- The use of import contracts with neighboring systems
- The start-up of thermal peaking units,
- The use of interruptible load programs,
- Reduction to thirty-minute reserve and stability reserve,
- Application of voltage reduction
- The use of public appeals
- The use of cyclic load shedding to re-establish reserves

More than 96 percent of the subregion's generation comes from hydro and other renewable resources, such as wind and biomass. Therefore, there are no environmental or regulatory restrictions that could potentially impact reliability.

A wind generation forecasting system has been in use for more than four years and is subject to periodical improvements. Hourly updated forecasts are available to system control personnel and cover a 48-hour time horizon.

HQD has recently implemented a wind generation call for tenders restricted to community-based and First Nations-based wind plants (total of 500 MW). Transmission studies during the tendering process have shown that some of the smaller wind farms (typically less than 10 MW) chosen through this call will be integrated on the distribution system (specific to each individual circuit). Wind farm and circuit protection, as well as telecommunications will need to be customized for each project, but no particular operational issues are projected.

The use of Demand Response resources are also not expected to impact reliability. Relay operations are submitted to systematic and thorough analysis by TransÉnergie's "Analyses et comportement du réseau principal et des réseaux régionaux" (Bulk and Regional System Behavior and Analysis) unit, where primary causes of relay operations are determined and scrutinized. When misoperations occur, the unit will issue recommendations and suggest corrective actions to other installations as necessary. This is done through Maintenance Notices issued to Maintenance Units. Recommendation follow-up is certified through the SADA system.

Concerning protection equipment sustainability, a TransÉnergie Working Group ensures that control and protection system data continually updated. A log sheet containing replacement priorities and timelines for protection equipment is also maintained. Annual reviews are conducted to reevaluate priorities and account for accomplishments and identify any remaining tasks. Evaluations of problematic systems are kept on file for reference.

Wind Farm Integration to Grid

Timeframe

- The time frame for this issue is mostly in the 1-5 year range. Presently there is 659 MW of wind power installed on the system. This is scheduled to go up to 3,500 MW through years 2015-2016.

Emerging or Standing Issue

- This is a standing issue. TransÉnergie has identified the issue and modeling work has begun. Contacts with wind turbine suppliers are under way and studies are being done.

Changes to Reference Case

- No change in the LTRA data.

Projected Long-Term Impacts

- No change outside the reference case.

Regional Reliability Impacts

- The impact is contained inside the Québec subregion. The Québec Interconnection is frequency sensitive but all its interconnections with other subregions in the Eastern interconnection are through HVdc systems or through radial generation.

Resource Adequacy Considerations

- None.

Transmission Adequacy Considerations

- This issue affects frequency support in Québec since the present generation of wind farms does not partake in frequency support after a fault and/or generation loss.

Resource Development Issues

- None.

Operational Impacts

- This issue will not directly affect operations. Mitigation will be offered through the use of built-in inertia emulation modeling specified by TransÉnergie for all wind turbine manufacturers.

Additional Information

By 2015, Hydro-Québec plans to integrate approximately 3,300 MW of nameplate wind capacity. The system is a separate NERC Interconnection and asynchronous with its neighboring systems. It is therefore responsible for its own frequency regulation. Installed capacity amounts to approximately 42,400 MW and system inertia will be lower than the Eastern Interconnection. For example: large post-contingency frequency excursions (as high as ±1.5 Hz) can occur after normal contingencies. Therefore, operating limits have been set based on post-contingency frequency behavior.

This large scale integration of wind capacity has triggered the need for wind plants to provide additional frequency support to maintain actual system performance; TransÉnergie has requested manufacturers to add an inertia emulation function to compensate for the lack of inertia and spinning reserve from modern variable speed wind turbines. TransÉnergie is quantifying inertia emulation needs and in the process of procuring and validating manufacturers' inertia emulation model functions for wind plants. Inertia emulation is required for Hydro-Québec Distribution's wind generation resulting from the second and third calls for tenders, totaling 2,295 MW of capacity. Further studies will be necessary to ensure the reliable integration of wind capacity in the mid-term.

Equipment Ageing and Sustainability

Timeframe

- The time frame for this issue is mostly in the short and long-term (1-10 year range). Simulations on a 50-year basis are conducted to ascertain that long term decisions are made in due time concerning equipment sustainability.

Emerging or Standing Issue

- This is a standing issue. Equipment ageing has been the subject of continuous studies for many years and a detailed global strategy has been filed with the Québec Energy Board in 2007 for substations and in 2010 for lines.

Changes to Reference Case

- No change in the LTRA data.

Projected Long-Term Impacts

- No change outside the reference case.

Regional Reliability Impacts

- Impacts are contained inside the Québec area for any equipment inside the area. For interconnections with other areas impacts may be bilateral, requiring coordination between areas.

Resource Adequacy Considerations

- None.

Transmission Adequacy Considerations

- On the very long term equipment ageing considerations (and thorough planning thereof) are important to maintain equipment performance and availability.

Resource Development Issues

- None.

Operational Impacts

- Outage planning will impact operations since outage needs will grow in the future. Optimizing and coordinating maintenance outages and project oriented outages is important so as to limit impacts on the system.

Additional Information

Aging equipment – especially line and station equipment – and sustainability have been standing issues at Hydro-Québec TransÉnergie for more than 15 years However, during the past decade, it became obvious that a global strategic investment policy was needed to address this issue. A strategy was developed based on the risk (sustainability) of loosing equipment due to a major failure, with focus on equipment approaching the end of its life cycle. This risk assessment considers the probability of a major failure and the potential impact on the transmission system and on TransÉnergie as an asset owner. This strategy, proposed in 2007, was presented to, and authorized by the Québec Energy Board, with an accompanying annual budget. Issues that could impact reliability in the context of equipment ageing are the following:

- Significant reductions in investment
- Personnel and equipment availability for maintenance outages as well as for new projects
- System availability for outages

Currently, these issues are not expected to impact bulk power system reliability.

Assessment Area Description

The Québec Assessment Area experiences peak demand during the winter season, with summer peak demand amounting to only 55 percent of the winter. The all-time internal peak demand was 37,717 MW, set on January 24, 2011.

The Québec sub-region is a separate interconnection and other NPCC Assessment Areas are tied to the Eastern Interconnection. TransÉnergie, (the Transmission Owner (TO) and Transmission Operator (TOP) for Québec) is interconnected with the Maritimes, Ontario, New York, and New England systems through either HVdc ties or radial generation. There may also be additional load to and from neighboring systems. Approximately 8 million customers are served within the Québec Assessment Area, which covers approximately 1,668,000 square kilometers (644,300 square miles). Although most of the population is located in the St. Lawrence River basin, the largest load is in the southwest part of the province, near Montréal, extending south to the city of Québec

PJM

Introduction

Along with being a Regional Transmission Operator, PJM is a Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner and Transmission Service Provider for its footprint. PJM is the largest single Balancing Authority in the world with an all-time peak load of over 145,000 MW. With the recent additions of FirstEnergy (ATSI), Cleveland Public Power (CPP) and Duke Ohio and Duke Kentucky (DEOK) into PJM, 2011 peak load is expected to exceed our all-time peak.

The forecast for the 2011 PJM RTO summer peak is 148,941 MW which includes the integration of FirstEnergy (ATSI) and Cleveland Public Power (CPP) into PJM. FirstEnergy (ATSI) and CPP load is expected to contribute 13,364 MW to the 2011 PJM peak. The forecast for the 2012 PJM RTO summer peak is 158,631 MW which includes the integration of Duke Ohio and Duke Kentucky (DEOK) into PJM. Duke's load is expected to contribute 4,500 MW to the 2012 PJM peak. Summer peak load growth for the PJM RTO (with ATSI, CPP and DEOK) is projected to average 1.3 percent per year over the assessment period. Because of the significant differences with the addition of FirstEnergy (ATSI), CPP and DEOK comparisons with previous years are misleading. Significant differences in the forecast of Net Internal Demand from the 2010 Load Report result from including the load of FirstEnergy (ATSI) and CPP starting in June 2011 and DEOK starting January 2012, a weaker economic forecast, and an increase in expected load management and Energy Efficiency impacts. The PJM RTO (with ATSI, CPP and DEOK) summer peak is forecasted to be 176,060 MW in 2021, an increase of 21,677 MW. PJM has 180,406 MW of *Existing-Certain* capacity for the 2011-2012 planning period. With the addition of ATSI, CPP and DEOK and changes in the other PJM companies, the PJM generating resources have increased 13,000 MW. *Future-Planned* capacity resources increase by 9,500 MW by the end of the assessment period. No *Future-Other* or Future-Inoperable resources are considered. PJM has several significant capacity additions, including a large coal unit, several large natural gas-fired units, significant amounts of wind and solar development and a nuclear unit in Virginia. The PJM Assessment Area's Reserve Margin requirement ranges from 15.6 and 15.3 percent from 2011-2021. PJM is expected to meet its Reserve Margin requirements through the entire assessment period (except for the last planning period in 2021), but it has 27,000 MW of on-peak *Conceptual* generation in the interconnection queues, of which approximately 20 percent is expected to come on-line. No subregions exist in PJM. No resource-related reliability concerns were identified.

The Trans-Allegheny Interstate Line (TrAIL) Project (502 Junction to Mt. Storm 500 kV line, Mt. Storm to Meadowbrook 500 kV line and the Meadowbrook to Loudoun 500 kV line) and Carson-Suffolk 500 kV line went in service during the spring 2011.

PJM expects the following lines to go into service during the assessment period:

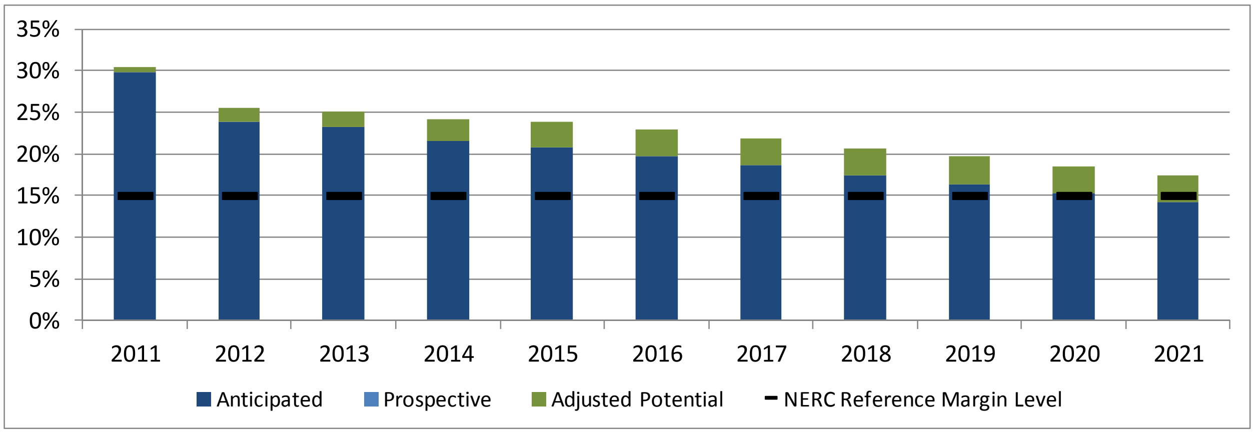
- Susquehanna-Roseland 500 kV line
- Amos-Kemptown 765 kV line, also known as the PATH line
- Possum Point-Indian River 500 kV line, also known as the MAPP line
- Branchburg-Roseland-Hudson (B-R-H) 500 kV line

No additional transmission reliability concerns have been identified. Operation of the system during off-peak times with maintenance outages of transmission lines still presents challenges for PJM operators. Operators have chosen to not grant outages if reliability would have been threatened with those lines out.

Reliability Assessment

The PJM Reserve Margin requirement for 2011-2012 is 15.6 percent, for 2012-2013 is 15.5 percent, is 15.3 percent for 2013-2014 through 2015-2016 and is 15.4 percent for 2016-2017 through 2018-2019. PJM is expected to meet its Reserve Margin requirements through the entire assessment period, except the last planning period (2021) but has over 40,000 MW of nameplate generation in its interconnection queues (Figure 106).

Figure 106: Annual On-Peak Planning Reserve Margins



Assuming just existing and planned resources are in service, PJM will meet its Reserve Margin requirements in 2020 (15.3 percent requirement), and is projected to be less than 1 percent deficient (approximately 800 MW) in 2021 (15.3 percent requirement). The 2020 deficiency is primarily due to the time period being further out than any PJM Stakeholder projections regarding future capacity plans and we fully expect that the required amount, from the 40,000 MW of nameplate *Conceptual* capacity, will come on-line. PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in 10-years, per RFC Standard BAL-502-RFC-02. PJM performs an annual LOLE study to determine the Reserve Margin required to satisfy this criterion. The study recognizes, among other factors, load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. The methods and modeling assumptions used in this study are available in PJM Manual 20 and in Appendix A of the 2010 Reserve Requirement.[271,272]

[271] The latest resource adequacy study, the PJM Reserve Requirement Study, was completed on September 30, 2010: http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx.

[272] This study examined the period 2010-2020: http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx.

PJM existing and planned resources climb from approximately 180,000 MW in 2011 to over 189,700 MW by the end of 2021. Only resources committed to the PJM RPM market and planned capacity additions were counted towards meeting the PJM Reserve Margin requirement. PJM's reliance on external emergency assistance for planning purposes is called the Capacity Benefit Margin (CBM) and is coordinated with OASIS postings. The resulting assistance is probabilistic in nature due to methods used in the LOLE calculations. The various OASIS Available Transfer Capability values are decremented in total by this CBM value of 3,500 MW; with each path receiving a portion of this reduction (Total reduction of all paths into PJM is 3,500 MW). Currently, per Schedule 4 of the Reliability Assurance Agreement, 3,500 MW is reserved for assistance from neighboring regions. This assistance is consistent with Operational experience and practices and considers the neighboring regions to be at the same reliability level (1 in 10 criteria) in providing this assistance. This treatment of CBM is in compliance with NERC MOD-004-1 and MOD-008-1.

The PJM reserve requirement is calculated and required for up to three years into the future. PJM calculate a PJM Reserve Requirement (RRS) for an 11 year period, on an individual planning period basis. In the planning window of the RRS, a Commercial Probability is applied to the generator interconnection queues to determine how much generation in aggregate should be applied to our adequacy in longer-term years. The use of CBM reduces the PJM reserve requirement by about 1.84 percent.

Behind the meter generation (BTMG) modeling: Per the June 28, 2004 PC meeting, BTMG may be treated as either a capacity resource or may be used to reduce load. The choice of the modeling method is left to the owner of the BTMG resource. PJM has very little hydro generation and expects no problems with warm cooling water. There are no anticipated fuel delivery problems during the summer when PJM experiences its peak. 43 percent of PJM generation has duel fuel capability with the PJM fleet enjoying a wide mix of fuel types. Transmission-limited and energy-only units are not typically considered in PJM reliability analysis. Some energy-only resources, per coordination with the PJM and TO planning staffs, can be modeled in load deliverability assessments that feed into the RPM Marketplace.[273] They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance[274] the calculation procedure for capacity credit is determined. The variable resource is represented in the Adequacy LOLE studies at this reduced amount (based on nameplate rating) at 100 percent availability (*i.e.,* zero forced and planned outage).

Many states in PJM have Renewable Portfolio Standards. It is up to the states to incent renewable development. PJM will assist with the interconnection studies to build transmission to bring the renewables to the PJM market. Variable resources are counted partially for PJM resource adequacy studies. Initially, both wind and solar, use standardized capacity factors of 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual plant's capacity factor (reduction of nameplate

[273] See section four of PJM Manual 20, revision 4: http://www.pjm.com/~/media/documents/manuals/m20.ashx.

[274] Per Appendix B of PJM Manual 21: http://www.pjm.com/~/media/documents/manuals/m21.ashx.

rating).[275] The variable resource is represented in Adequacy studies at this reduced amount (based on nameplate rating) at 100 percent availability (*i.e.,* zero forced and planned outage). Variable resources are treated in a similar manner as other capacity resources but with the resource adequacy assumptions mentioned previously per Appendix B of PJM Manual 21. We have a small penetration of variable resources at this time and may develop other approaches in the future if necessary.

PJM's resource adequacy studies model only those demand response programs that are programs committed to PJM and under the direction of PJM Operations. Compliance with a PJM call for interruption is mandatory for these demand response programs. At the conclusion of each summer, these demand response programs must submit data to PJM verifying their ability to interrupt load up to their full value. Failure to provide such data will result in a significant financial penalty to the demand response provider.[276]

3,600 MW of generator retirements have been identified through the assessment period. Generator retirements are evaluated for reliability impacts as each retirement is proposed. If it is determined that a reliability impacts exists, the unit will not be allowed to retire until the reliability impacts are addressed.[277]

The FirstEnergy ATSI system does use a UVLS scheme that was originally installed in 2005 to provide an effective method to prevent uncontrolled loss-of-load following extreme outages (Category D) like loss of an entire substation. The UVLS scheme is not intended to bring the system to an acceptable post-contingency condition. Rather, it is intended to stabilize the system and prevent an uncontrolled cascading outage. It is anticipated that Operator action will be required to bring the system to a post-contingency state with acceptable voltages and flows. Note that prior to the 2005 installation of the UVLS scheme, FirstEnergy ATSI reviewed the results and recommendations of the original UVLS study (performed by GE in 2004 for the forecasted 2011 peak load level) with ECAR and MISO and requested and received approval from ECAR to move forward with the installation.

PJM has several special protection systems (SPS) permanently installed. Every SPS that monitors or acts on the PJM bulk power system must be functionally redundant. At this time no SPSs are planned but SPSs are a valid way to mitigate criteria violations especially in the short-term.

PJM has documented operating procedures in the PJM Emergency Procedures Manual (M13) Section 3:[278] *Weather/Environmental Emergencies* and Section 4: S*abotage/Terrorism Emergencies. Reporting of System Emergencies* is documented within Section 6: *Reporting Emergencies* and Attachment J: *Disturbance Reporting*, provided by the US Department of Energy.

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[275] For calculation details. see Appendix B of PJM Manual 21: http://www.pjm.com/~/media/documents/manuals/m20.ashx.

[276] In addition the recent FERC order ER11-2288-000 about PJM DR saturation filling is document in Section 5 of PJM Manual 20, revision 4: http://www.pjm.com/~/media/documents/manuals/m20.ashx.

[277] Generator retirement information is available on the PJM website: http://www.pjm.com/planning/generation-retirements.aspx .

[278] http://www.pjm.com/~/media/documents/manuals/m13.ashx.

Regional Transmission Expansion Plan (RTEP) identifies transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM customers. PJM's region-wide RTEP approach integrates transmission with generation and load response projects to meet load-serving obligations. PJM currently applies planning and reliability criteria over a fifteen-year horizon to identify transmission constraints and other reliability concerns. Transmission upgrades to mitigate identified reliability criteria violations are then examined for their feasibility, impact and costs, culminating in one plan for the entire PJM footprint.

Developers requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit or decommissioning of a generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM's defined interconnection process. This process ensures the successful, timely completion of PJM's planning, facility construction and operational and market infrastructure requirements. The term Developer is used to encompass any entity which bears responsibility for bulk power system upgrades, whether a third party seeking interconnection.

Post-contingency voltage constraints can limit the amount of energy that can be transferred through portions of the PJM RTO. The PJM EMS performs automated full AC security analysis transfer studies to determine Transfer Limits for the use in real-time operation. The PJM Transfer Limit Calculator (TLC) simulates worse case transfers, with the simulation starting point being the most recent State Estimator solution. The TLC determines a collapse point for each interface that is then considered the IROL for that interface. Each interface consists of a number of 500 kV lines. A megawatt transfer limit is then created by backing off the IROL limit by a predetermined amount. The reactive limits are pre-contingency megawatt limits based on post-contingency voltage drop. The PJM dispatchers continuously monitor and control the flow on each transfer interface so that the flows remain at or below the transfer limits. This ensures that no single contingency loss of generation or transmission in or outside the PJM RTO causes a voltage drop greater than the applicable voltage drop criteria. PJM operates to the transfer limit which is less than the defined reactive transfer IROL limit.

In addition to the thermal limits, PJM operates considering voltage and stability related transmission limits as follows:

- Voltage Limits – High, Low, and Load Dump actual voltage limits, high and low emergency voltage limits for contingency simulation, and voltage drop limits for wide area transfer simulations to protect against wide area voltage collapse.
- Transfer Limits – The MW flow limitation across an interface to protect the system from large voltage drops or collapse caused by any viable contingency.
- Stability Limits – limit based on voltage phase angle difference to protect portions of the PJM RTO from separation or unstable operation.

PJM has implemented an Intelligent Event Processor, which uses telemetered values and calculations to alarm operators of relevant operating procedures. PJM is in the process of implementing a new Energy Management System and real-time Transient Stability Analysis tool. Several PJM entities are moving forward with extensive smart metering projects, electric vehicle management programs, utility size batteries and enhanced communication initiatives. No Smart Grid projects are expected to have a detrimental effect on reliability.

Recent Environmental Protection Agency regulations could have an effect on whether a generating unit will continue to run, be retrofitted or retired. The PJM RTEP process will take these retirements, if any, into account in future reliability plans. No significant retirements related to the recent environmental regulations have been identified that will effect reliability. Some retirements have recently been announced by PJM Generator Owners but these retirements have not yet entered the PJM RTEP process. No transmission upgrades have been identified specifically related to generation retirements.

There are no anticipated project slow-downs, deferrals or cancellations which may impact reliability in PJM, however, some projects have been delayed or cancelled based on reduced load forecasts as a result of increase in Demand Response and a poor economy.

Demand

Summer peak load growth for the PJM RTO (with ATSI and DEOK) is projected to average 1.53 percent per year by 2021, and 1.1 percent over the next 15 years. In comparison, the 2010 forecast for the PJM RTO was projected to average 1.7 percent per year for the 10-year growth rate and 1.5 percent for the 15-year growth rate. The PJM RTO (with ATSI and DEOK) summer peak is forecasted to be 176,060 MW in 2021, a total increase of 27,119 MW (Table 100).

Table 100: Assessment Area Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	148,941	176,060	27,119	1.53%	18.2%
Net Internal	137,341	167,081	29,740	1.80%	21.7%

Annualized 10-year growth rates for individual PJM transmission zones range from 0.6 percent to 2.1 percent. Significant differences in the forecast of Net Internal Demand from the 2010 Load Report result from including the load of American Transmission Systems, Inc (ATSI) starting in June 2011 and Duke Energy Ohio/Kentucky (DEOK) starting January 2012, a weaker economic forecast, and an increase in expected Load Management and Energy Efficiency impacts.

The PJM demand forecast included noncoincident and RTO coincident models for each PJM zone. The PJM load forecast process produced a weather distribution of peak load forecasts by applying a Monte Carlo simulation using 37 years of historical weather from 1973 to 2009. The economic variable used in the PJM load forecast is Real Gross Metropolitan Product (GMP) for major metropolitan areas within the RTO. The current forecast uses the December 2010 economic forecast release from Moody's Economy.com which was revised in January 2011 for three Ohio metropolitan areas (Cleveland, Cincinnati, and Dayton). The 2011 forecast uses economics that show weaker growth compared to the economics used in the 2010 forecast. For the PJM RTO, the assumption for economic growth for this long-term assessment forecast is for GMP to grow at a compound average growth rate of 1.9 percent for 2011 to 2021. PJM forecasts the load of the entire RTO and the individual transmission zones on a coincident basis. Since PJM is summer-peaking, the coincident summer peaks are used in resource adequacy evaluations.

Energy Efficiency programs included in the 2011 load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). At time of the 2011 load forecast publication, 170 MW, 386 MW, and 563 MW of Energy Efficiency programs have been approved as RPM resources in 2011, 2012, and 2013 respectively.[279] To demonstrate the value of an Energy Efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing M&V plans, providing post-installation M&V reports, and undergoing an M&V audit. For the 2010/2011 delivery year PJM had contractually interruptible demand side management of 11,826 MW (Table 101). Values are anticipated to increase through the assessment period. For example, the 2014-2015 BRA saw 14,118 MW of demand resources clear in the auction. PJM does not have knowledge of how or if DSM resources or Energy Efficiency is specifically used for meeting state renewable portfolio standards (RPS) of its members. PJM itself is not subject to an RPS.

Table 101: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**170**	**563**	**393**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	-	-	-
Contractually Interruptible (Curtailable)	-	-	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	11,826	11,826	-
Total Dispatchable, Controllable Demand Response	**11,826**	**11,826**	**-**
Total Demand-Side Management	**11,996**	**12,389**	**393**

The PJM load forecast process produces a weather distribution of peak load forecasts by applying a Monte Carlo simulation using 37 years of historical weather from 1973 to 2009. The official peak load forecast is the median (50/50) value but extreme peak forecasts (90/10) are also published. PJM demand forecasting methods have not fundamentally changed in the last year.

Generation

PJM has 180,406 MW of *Existing-Certain* capacity for the 2011-2012 planning period. *Future-Planned* resources increase the capacity by 9,500 MW by the end of the assessment period. Projected on-peak capacity mix by fuel type, and the annual net capacity changes from 2011-2021 are shown below (Figure 107 and Figure 108).

[279] Measurement and verification of Energy Efficiency programs are governed by rules specified in PJM Manual 18B: http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

Figure 107: On-Peak Capacity Mix by Fuel Type

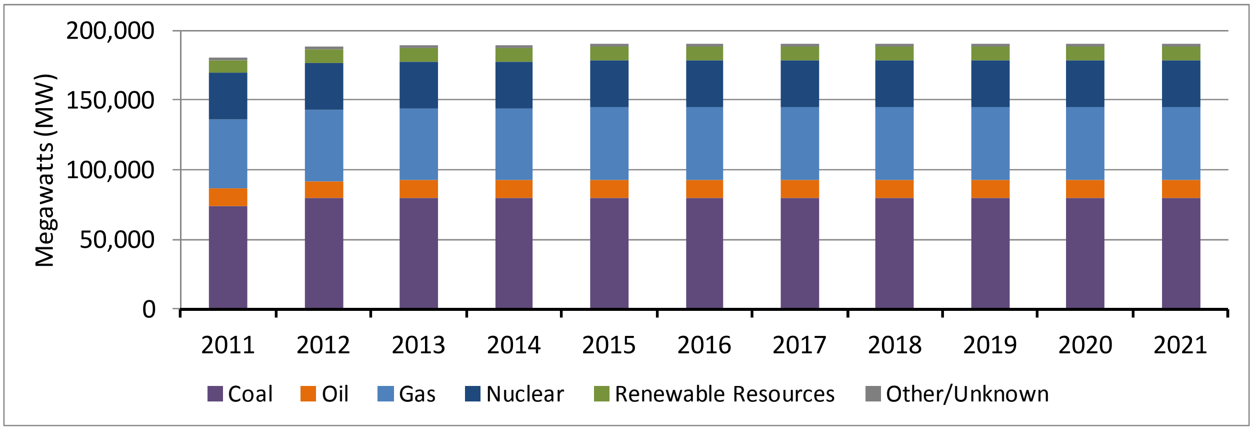
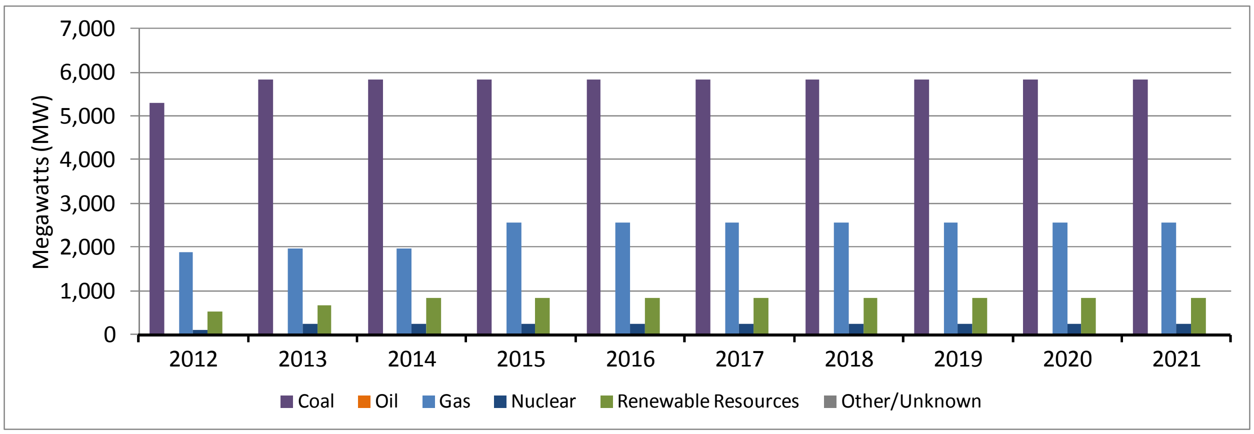


Figure 108: Annual Net Capacity Change by Fuel Type



Nameplate wind resources amount to 4,942 MW in 2011, with projected additions of 2,069 MW of *Future-Planned* and *Future-Other* capacity additions during the assessment period. Expected on-peak wind is presently 670 MW and is expected to increase by 469 MW by 2021. There are currently 32 MW of nameplate solar resources in PJM, with plans for over 306 MW to be added during the assessment period. Expected on-peak solar is now 12 MW and is expected to increase by 127 MW by the end of the assessment period. Finally, 880 MW of nameplate biomass capacity exists in PJM with an additional 69 MW planned during the assessment period. All related figures are shown below (Table 102).

Table 102: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	670	1,138	469
	Derated	4,273	6,341	2,069
	Wind - Total Nameplate Capacity	**4,942**	**7,480**	**2,537**
Solar	Expected	12	127	115
	Derated	20	211	191
	Solar - Total Nameplate Capacity	**32**	**338**	**306**
Hydro	Expected	2,623	2,799	177
	Derated	9	9	-
	Hydro - Total Nameplate Capacity	**2,632**	**2,808**	**177**
Biomass	Expected	879	947	68
	Derated	0	1	1
	Biomass - Total Nameplate Capacity	**880**	**949**	**69**

Variable resources are only counted partially for PJM resource adequacy studies. Initially, both wind and solar initially use class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor.

PJM has a total of 27,700 MW of on-peak *Conceptual* capacity that may come on-line over the assessment period. *Conceptual* nameplate wind resources are expected to increase by 33,400 MW over the assessment period. *Conceptual* on-peak wind is expected to increase 6,250 MW over the assessment period. 3,700 MW of nameplate *Conceptual* solar is proposed amounting to 1,400 MW of on-peak solar. PJM has 460 MW of *Conceptual* biomass for the assessment period.

Only *Existing-Certain* capacity and *Future-Planned* capacity are counted towards meeting the reserve requirement in PJM. No *Conceptual* capacity is counted until an Interconnection Service Agreement is executed. All proposals for new generation come through the PJM Regional Transmission Expansion Process to determine required transmission expansion if necessary. The calculation of Commercial Probability uses historically gathered information to assign probabilities to each milestone category (signed ISA, submitted, etc.). The probability percentages are applied to the amount of queued resources in each category to come up with a commercial probability for aggregate resources for each year out. All queued resources are categorized into four stages of the RTEP interconnection process. The stages are feasibility study complete, impact study complete facility study complete and signed Interconnection Service Agreement.

Distributed generation, if elected as PJM capacity in the RPM Market, is counted towards meeting the PJM load and reserve requirements just like any other generator. Behind-the-Meter generation is not counted towards meeting the PJM load and reserve requirements but typically somewhat offsets local load.

Capacity Transactions

Expected Firm imports range from a total of 3,858 MW in 2011 to approximately 4,768 MW in 2021 for the PJM RTO (Table 103). There are no expected or provisional transactions counted towards meeting the Reserve Margin requirements. All transactions are Firm for both generation and transmission. None of PJM's imports are based on partial path reservations.

Table 103: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	3,858	4,768	3,858	4,768
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**3,858**	**4,768**	**3,858**	**4,768**
Exports	Firm	2,598	2,632	2,598	2,632
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**2,598**	**2,632**	**2,598**	**2,632**
Net Transactions		**1,260**	**2,136**	**1,260**	**2,136**

Expected Firm exports total approximately 2,600 MW for the entire assessment period for the PJM RTO. There are no expected or provisional transactions. All transactions are Firm for both generation and transmission.

Transmission

Since 2006, the PJM Board has approved six new major 500 kV and 765 kV backbone upgrades (all Planned, no *Conceptual* discussed):

- 502 Junction-Loudoun 500 kV line, also known as TrAIL (2006 RTEP)
- Carson-Suffolk 500 kV line (2006 RTEP)
- Susquehanna-Roseland 500 kV line (2007 RTEP)
- Amos-Kemptown 765 kV line, also known as the PATH line (2007 RTEP)
- Possum Point-Indian River 500 kV line, also known as the MAPP line (2007 RTEP)
- Branchburg-Roseland-Hudson (B-R-H) 500 kV line (2008 RTEP)

Summarized below, the importance of these facilities was reconfirmed in PJM's 2010 RTEP cycle of analyses. In the case of the B-R-H line, a replacement solution comprising local 230 kV upgrades was approved in light of fewer and less severe reliability criteria violations.

Amos-Welton Springs-Kemptown (PATH) 765 kV Line

As part of the RTEP 2010 process, analysis, and review of proposed alternatives, the PJM Board reaffirmed the need for the PATH project as the most robust solution to identified reliability criteria violations and given the need for a solution to be in place by June 1, 2015. Both thermal and reactive testing identified NERC Reliability criteria violations out through PJM's 15-year planning horizon. In summary, PJM identified 25 thermal violations on ten 500 kV transmission lines beginning in 2015. In addition, PJM identified 55 thermal violations based on NERC Category C3 (n-1-1) testing. PJM also identified 187 separate voltage violations on 500 kV transmission facilities that relate to the need for the PATH Project.

The number and severity of the voltage violations identified in the 2010 Baseline Analysis continued to indicate underlying systemic weakness in the transmission system's ability to move energy in a capacity emergency. Moreover, the severe consequences of these violations would be felt over a wide area, including much of the PJM Region east of the Allegheny Mountains, including eastern West Virginia, Maryland, Delaware, Eastern Pennsylvania and Virginia. PJM also evaluated a number of alternatives to PATH as part of the 2010 RTEP process, including both transmission line and reactive-only options. PJM's analysis revealed the PATH Project to be the most effective, robust long-term solution to the identified thermal and reactive reliability criteria violations out through PJM's 15-year planning horizon.

Possum Point-Indian River (MAPP) 500 kV Line

Based on 2010 RTEP baseline analysis, PJM confirmed the need in 2015 for the MAPP Project. The MAPP project was confirmed by the PJM Board with a required in service date of June 1, 2015. The MAPP project proved more effective than alternatives at resolving violations in light of identified estimated costs and completion times.

In summary, the 2010 RTEP baseline analysis PJM identified numerous NERC Reliability Standard voltage violations, including multiple voltage collapse conditions for the contingency loss of certain 500 kV facilities. Load deliverability tests identified 12 voltage drop violations, six voltage magnitude violations and five voltage collapse violations beginning in June 2015.

In certain cases, voltage collapse occurred before the required transfer capability requirement was reached. Specifically, the Keeney to Rock Springs 500 kV line contingency is projected to cause a precipitous voltage collapse with little or no warning to system operators. Unlike other identified violations the voltage collapse result was not preceded by other voltage violations. This type of system scenario is among the most difficult to forecast and control from an operational perspective. Each of the identified voltage violations is resolved by the MAPP Project. The use of Direct Current (DC) technology for the portion of the MAPP Project under the Chesapeake Bay improves reliability into the eastern Mid-Atlantic and allows for higher energy flows from the southwest onto the Delmarva Peninsula than previously observed using Alternating Current technology. DC technology also provides controllability for improved operational performance. This further enhances reliability in the Mid-Atlantic region by reducing energy flows on critical 500 kV transmission facilities on the PJM eastern and central interfaces and has the ability to facilitate the integration of off-shore renewable generation resources.

Northern New Jersey

PJM's 2010 annual Regional Transmission Expansion Plan (RTEP) process assessed Bulk Electric System (BES) facilities throughout New Jersey for compliance with NERC reliability criteria violations. A series of NERC reliability criteria contingency violations were identified in Northern New Jersey, requiring the need for baseline transmission upgrades.

First approved for RTEP inclusion in 2008, the Branchburg-Roseland-Hudson (B-R-H) 500 kV transmission line solved those violations. However, while 2010 baseline analysis continues to identify criteria contingency violations, a 230 kV solution was approved by the PJM Board, replacing the B-R-H 500 kV transmission line in PJM's RTEP, as discussed in Section 7.

Susquehanna-Roseland

The PJM Board approved the Susquehanna-Roseland 500 kV line in 2007 to resolve numerous overloads on critical 230 kV circuits across Eastern Pennsylvania and Northern New Jersey beginning in 2012.

A 2012 baseline retool study conducted as part of PJM's 2010 RTEP process identified five NERC reliability criteria violations, confirming the need for the Susquehanna-Roseland 500 kV line. Given the number of facilities experiencing violations and the extent to which they do so, incremental upgrades are not a practical solution.

The Pennsylvania Public Utility Commission approved the line on February 12, 2010. The New Jersey Board of Public Utilities approved the line on February 11, 2010. However, transmission owners PPL and PSEG, responsible for construction of the line, have indicated that the line won't be in service until June 1, 2014 or later, primarily due to delays in obtaining a permit from the National Park Service for the 1.65 mile line segment that crosses the Delaware Water Gap National Recreation Area, the Appalachian National Scenic Trail and the Middle Delaware National Scenic and Recreational River.

PJM has developed an operational solution to address the criteria violations that would otherwise be expected to occur in 2012 without the Susquehanna-Roseland line. The operational solution includes extending the Reliability Must Run (RMR) status for Hudson Unit #1 into 2012 and operating to the NERC category C double circuit tower line contingencies that are driving the need for the line. Operating to the double circuit tower line contingencies will provide PJM Operations staff the time needed to implement demand resources to manage flow on constrained facilities once generation re-dispatch options have been exhausted. Analysis shows the combination of retaining the Hudson Unit #1 on RMR along with implementing demand resources would be effective at controlling the thermal violations expected to occur in 2012 without the Susquehanna-Roseland line.

Aging Infrastructure: Mt. Storm-Doubs 500 kV Rebuild

Mitigating operational risk is driving the need to rebuild the existing Mt. Storm - Doubs 500 kV line, in-service since 1966. Aging towers and other structural degradation make consideration of this rebuild a priority. Over the course of the past 45 years, despite ongoing maintenance efforts, tower structures, foundations and conductor hardware have deteriorated to the point where the line is approaching its end-of-life and is at risk of major failure. Rebuilding the line will improve regional reliability and reduce congestion along a major corridor that feeds power to northern Virginia and PJM's Mid-Atlantic region.

The Mt. Storm-Doubs 500 kV line has been a limiting element and, consequently, a major driver of system reinforcements since PJM's 2006 RTEP cycle. The TrAIL project itself was added to the RTEP in 2006 primarily the result of overloads on the Mt. Storm-Doubs line. The PATH line was added to PJM's RTEP as part of 2007 RTEP analysis to address further overloads on the line. Even with the TrAIL and

PATH lines included, long-term planning studies conducted as part of the 2010 RTEP indicate line loading levels exceeding 95 percent of the applicable rating by 2025. Going forward, within its existing 150 foot right-of-way, the rebuilt line will use taller structures and line hardware increasing its existing 2,598 MVA rating by 65 percent to 4,300 MVA.

TrAIL Project

Meadowbrook to Loudoun 500 kV was energized on April 13, 2011. Mt. Storm to Meadowbrook 500 kV was energized on May 13, 2011 and the 502 Junction to Mt. Storm 500 kV line was energized on May 19, 2011. The TrAIL 500kV Line in the Allegheny Power/Dominion areas will increase import capability into the Baltimore/Washington/Northern Virginia area by approximately 1,000 MW. The AP South Interface capability is increased by approximately 500 MW. The TrAIL line met a required June 1, 2011 in-service date, specified by PJM to solve identified NERC reliability criteria violations.

Carson-Suffolk 500 kV Line

The Carson-Suffolk 500 kV Line in Dominion is now in service. It strengthened the transmission system to the southern Dominion area. It met the required June 1, 2011 in-service date specified by PJM to solve identified NERC reliability criteria violations. PJM does not have any additional constraints than then ones mentioned above. PJM has 1,250 MVAr of dynamic reactive capability spread over five devices scheduled for installation by 2013. No other Flexible AC Transmission (FACTS) devices are planned for the assessment period.

Operational Issues

No near-term system operating issues are expected. Longer term operating issues having to do with transmission construction delays, as mentioned above, are possible. Available mitigating measures include re-dispatch of generation, operating procedures, and special protection schemes.

Variability of forecasted demand is accounted for in the determination of our required Reserve Margin. The PJM forecast uses a Monte Carlo process that produces forecasts using all weather experienced over the last thirty-five years. The resulting 455 scenarios are rank ordered, with the median value being the base forecast. This extensive distribution of forecasts allows for estimation of peak load uncertainty at all probability levels of weather. PJM implements emergency procedures identified in the PJM Emergency Procedures Manual (M13), Section 2: Capacity Conditions.[280]

PJM requires Generation Owners to place resources into the "Maximum Emergency Category" if environmental restrictions limit run hours below pre-determined levels. Max Emergency units are the last to be dispatched and represent the highest cost megawatts on the system. A specific operating step is used to call Maximum Emergency units on-line and is the last operating step during a capacity shortage before an actual emergency is called. There are no environmental restrictions expected to affect reliability through the assessment period since the restricted units amount to little megawatts (less than 500 MW) and only kick in after the units run for a period of time.

[280] http://www.pjm.com/~/media/documents/manuals/m13.ashx.

Integration of variable generation in PJM has not been a problem so far. PJM continues to investigate bulk power storage and increased regulation but no plans exist for changes to operations. The existing and planned amounts of distributed generation are very small in PJM and has not been or expected to be a problem.

Demand Response is used to assist in maintaining reliable operations during peak load conditions and no detrimental characteristics have been observed. PJM is engaging in a review program to determine if accepted Demand Resources actually can participate as required.

PJM works closely with Transmission and Generation Owners as part of the PJM Relay Subcommittee and PJM System Operations Subcommittees. Responsibilities of the Subcommittees, documented within their charter, include investigating and discussing misoperations in order to reduce reoccurrences.

Assessment Area Description

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM manages the high-voltage electricity grid to ensure reliability for more than 58 million people. The Assessment Area's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system wide basis.

SERC-E

Introduction

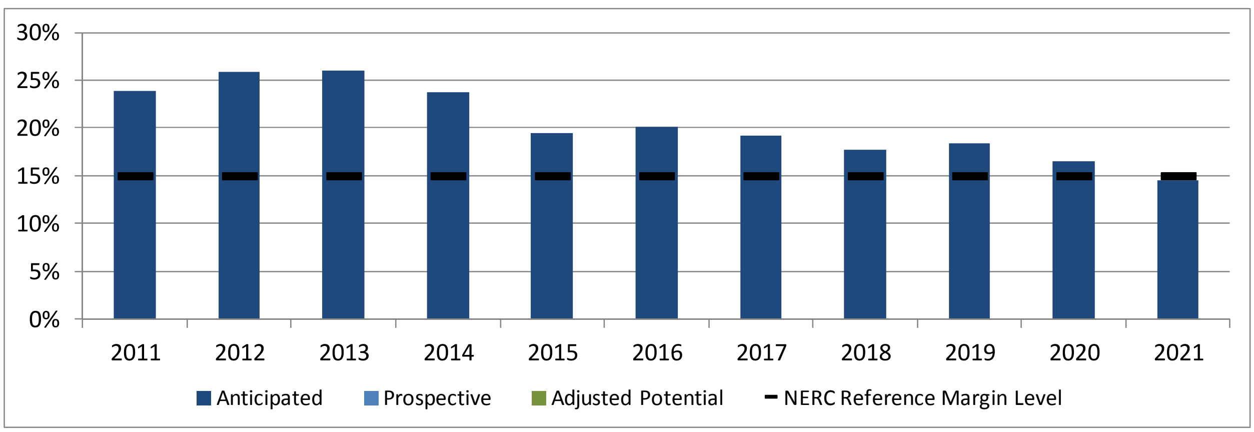
SERC-E is a summer-peaking reporting area covering portions of two southeastern states (North Carolina and South Carolina). There are five Balancing Authorities in SERC-E:

- Alcoa Power Generating, Inc. – Yadkin Division
- Duke Energy Carolinas
- Progress Energy Carolinas
- South Carolina Electric & Gas Company
- South Carolina Public Service Authority

Reliability Assessment

Projected anticipated net capacity resources Reserve Margins for utilities in the SERC-E area, as reported between 2011 and 2021, range from 26 percent to 14.6 percent. Margins fall below the NERC Reference Margin Level of 15 percent in 2021 (Figure 109); however, entities continue to project margins based on load reductions due to the economy, increased Demand-Side Management (DSM), significant increases in generation, and the effects of adverse weather on generating units. Utilities in the area report no expected problems with meeting demand for the period.

Figure 109: Annual On-Peak Planning Reserve Margins



Entities within SERC-E do not have a regional/reporting area target or Reserve Margin criteria. However, some utilities within this reporting area adhere to North Carolina Utilities Commission (NCUC) regulations. Other utilities establish individual target Reserve Margin levels to benchmark margins that will meet their needs for peak demand. Some assumptions used to establish the individual utilities' reserve/target margin criteria or resource adequacy levels are based on prevailing expectations of reasonable lead times for the development of new generation, procurement of purchased capacity, siting of new transmission facilities and other historical experiences that are sufficient to provide reliable power supplies. Assumptions may also include levels of potential DSM activations, scheduled maintenance, environmental retrofit equipment, environmental compliance requirements, purchased power availability, or peak-demand transmission capability/availability. Risks that would have negative impacts on reliability are also an important part of the process to establish these assumptions. Some of these risks would include the deteriorating age of existing facilities on the system, significant amount of renewables, increases in Energy Efficiency/DSM programs, extended base-load capacity lead times (for example coal and nuclear), environmental pressures, and derating of units caused by extreme hot weather/drought conditions. In order to address these concerns, companies continue to monitor these future risks and make any necessary adjustments to the Reserve Margin target in their future plans.

The Loss-of-Load Expectation (LOLE) standard of 1 day in 10 years is also used to address Reserve Margin targets. Annual LOLE studies help to determine the Reserve Margin required to satisfy this criterion. The studies recognize other factors such as demand forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources, and the benefit of interconnection with neighboring systems. Uncertainties are also addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed at least twice daily using input provided from generator operators. As conditions warrant, entities perform additional assessments to mitigate challenging conditions on the system. The most recent generation plans have identified the need for additional generation resources in the future to achieve planning margins. Entities will continue to perform studies and procure capacity as needed.

The latest resource adequacy studies[281] performed were completed in the fall of 2010. Results show that margins are projected to range from 11.1 percent to 20.0 percent for the 2011 summer. Some entities consider an 11.0 percent capacity margin to be a minimum and may be acceptable in the near term when there is greater certainty in forecasts. These studies also examined resource availability for multiple years. A minimum capacity margin target of 12.0 to 13.0 percent in the longer term was considered by one entity to provide an extra margin of reserves to compensate for possible load forecasting uncertainty, uncertainty in DSM and Energy Efficiency forecasts, or delays in bringing new capacity additions on-line, and uses this criterion to determine the need for generation additions.

Resource adequacy is assessed using various methods and assumptions that range from; LOLE studies (1 day in 10-years), loss of multiple unit studies, availability of the VACAR reserve sharing agreement, new environmental requirements, declining economic conditions, renewable energy, new generation technologies, rising commodity costs, forecasts for normal/severe weather cases with additional Firm capacity (existing, future and outage models included), and forecast demand plans on an annual/seasonal basis. In addition, forecasts for peak demand are generally made under a variety of both weather and economic conditions under RUS 1710 requirements.[282] From this analysis, resource plans are compiled accordingly. Overall, assuming that existing and planned resources are in-service, Reserve Margin requirements will be met for the period.

Utilities do not depend on resources from other regions or reporting areas to meet emergency imports and reserve sharing requirements. On average for the 11-year period, 54,861 MW of internal resources

[281] http://dms.psc.sc.gov/pdf/matters/0C817E1B-DAE3-3E6C-02B57E42EECA7021.pdf.

[282] Electronic Code of Federal Regulations, Title 7, Chapter XVII – Rural Utilities Service, Department of Agriculture: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&tpl=/ecfrbrowse/Title07/7cfr1710_main_02.tpl.

and 1,255 MW of capacity transactions were reported during this assessment period, which account for internal resources of non-reporting parties and for external resources.

Short- and long-term margins are generally not treated differently in utility studies. However, some entities have procedures in place to differentiate between the two margins. In such cases, short-term calculations apply to a three-year period. After three years, a probability is applied to the generator interconnection queues to determine how much generation in aggregate should be applied in the long-term. Overall, there is no reporting-area-wide confidence factor to determine margins within the *Conceptual* capacity category. The SERC-E reporting area has minimal distributed generation or behind-the-meter generation and they are not considered in meeting its Reserve Margin targets.

Fuel supply or delivery problems during the projected time period are not anticipated. Utilities within the reporting area have reported that their generation facilities expect to maintain enough diesel fuel to run the units for an entire order cycle of fuel. Ample resources are expected to address any short-term drought conditions or forced outages. Entities have ongoing communications with commodity and transportation suppliers to communicate near- and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Multi-stage contingency plans for hydro plants include procedures for managing lake levels and providing for minimum downstream flows, as well as preparations for acquiring alternate sources of cooling water. These plans are framed to ensure that potential interruptions can be addressed in a timely manner. However, hydro resources are a small portion of available generation in the area.

Transmission-limited and energy-only units are not considered in reliability analysis. Only Firm capacity resources are included in entity resource adequacy assessments and are either located inside the reporting area or are delivered over Firm transmission contracts.

As noted above, most entities do not include renewable resources in their capacity adequacy assessments. Entities within North Carolina have Renewable Portfolio Standards (RPS) renewable assumptions based on recent legislation.[283]

The overall requirements were applied to all native loads served by Duke Energy Carolinas (i.e., both retail and wholesale, and regardless of the location of the load) to take into account the potential that a Federal RPS may be imposed that would affect all loads. The requirement that a certain percentage must come from solar, hog and poultry waste was not applied to the South Carolina portions of load.

Those entities that have significant and reliable variable renewable resources may evaluate them the same as all other generation resources. Reduced capacity contributions for Reserve Margins are based on an estimated hourly energy profile. Performance over the peak period is tracked, and the class

[283] http://www.ncgreenpower.org.

average capacity factor is supplemented with historic information. Due to the limited availability of these resources, special planning procedures have not been developed at this time.
To address Demand Response in resource adequacy studies, some utilities have reported that they are provided with energy and cost data forecasts for current and projected DSM programs. These assumptions have been modeled in various programs such as System Optimizer[284] and PROSYM.[285] Sensitivities on DSM energy and cost projections are performed to understand the impact of the program's implementation on total system costs and annual Reserve Margins. Other companies note that Demand Response is considered a capacity resource. Standby generator programs and interruptible service programs help maintain the reliability of the system. One entity has reported that about 200 MW of capacity is available to the system through these programs.

Currently, Duke Energy has developed a timeline of expected retirement dates for approximately 800 MW of old-fleet combustion turbine units and 1,000 MW of non-scrubbed coal units. Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support the ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. A NCUC order (NCUC Order in Docket No. E-7, Sub 790)[286] granted the installation of Cliffside Unit 6, but required the retirement of the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit. The impact on reliability of the system, which accounts for actual demand reductions, is considered with the retirement of these units and other older coal-fired generating units. The requirement to retire older coal units is also set forth in the air permit for the new Cliffside unit. Retirements are scheduled for 350 MW of coal generation by 2015, 200 MW by 2016, and an additional 250 MW by 2018. If the Commission determines that the scheduled retirement of any unit pursuant to the plan will have a material adverse impact on system reliability, the utility is prepared to seek modification of the plan. For planning purposes, the retirement dates for these additional 800 MW of older coal units are associated with the expected verification of realized Energy Efficiency load reductions, which is expected to occur earlier than the retirement dates set forth in the air permit.

In order to address reliability issues in the future, utilities have considered using Under Voltage Load-Shedding (UVLS) schemes on their system. However, none of these programs are expected to be installed on the system during the time of this assessment. There are no Special Protection Systems (SPS) or Remedial Action Schemes (RAS) within SERC-E.

Utilities have addressed planning processes for catastrophic events in many ways. Some companies have procedures in place for system restoration, as well as capacity and emergency action plans. Other companies follow the practice of maintaining several days' worth of fuel oil at facilities in the event of natural gas disruptions. Resource portfolios are also used to address the issue. Portfolios are diversified with multiple resources mitigating the impacts of a major import path disruption. Sophisticated internal

[284] http://www.ventyx.com/analytics/system-optimizer.asp.

[285] http://www.ventyx.com/global/eu/analytics/market-analytics.asp.

[286] http://www.duke-energy.com/pdfs/NCUC-Cliffside-Order.pdf.

real-time systems have been developed by the utilities within the reporting area to track and analyze gas pipeline issues. These systems can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of a contingency analysis process. Depending on the advance notice, either operating plans can be adjusted or emergency procedures can be implemented. For the projected summer peaks, Reserve Margins are such that the loss of multiple units can be accommodated without threatening reliability.

Transmission planning practices are in accordance with the SERC Transmission System Performance NERC Reliability Standards TPL-001 through 004[287] reference document and NERC standard FAC-010[288] to test the system under stressed conditions. These practices have historically proven adequate to meet variations in operating conditions, forecast demand and generation availability. In addition, special transmission assessment studies are conducted as needed to assess unusual operating scenarios (*e.g.,* limitation on generation due to extended drought conditions). Utilities then develop any mitigation procedures that may be needed. Recent studies have identified no significant reliability issues.

Some utilities perform an operational peak self-assessment for anticipated and extreme winter/summer conditions, as well as an interregional analysis, in conjunction with neighbors to identify potential issues that may arise between areas. Tests are also done to assess various stability study criterion as well as stressed-system scenarios and contingencies. Studies of this type are routinely performed, both internally and through reporting area and Regional study group efforts. Results have initiated projects to build approximately 11 new transmission lines, 3 new transmission substations and a number of upgrades/modifications to existing facilities in the 2011 to 2021 timeframe. Some of these are to accommodate planned generation additions in Wayne County, NC and New Hanover County, NC.

Voltage stability and dynamic assessments/criteria studies are performed on an individual company basis within the reporting area. However, most entities participate in the Carolinas Transmission Planning Coordination Arrangement (CTPCA) to assess annual dynamic and voltage conditions on the system. In addition to guidance within the TPL-001 and TPL-002 NERC standards,[289] some entities have implemented a power flow criteria that the post-contingency voltage should be maintained at or above 0.95 per unit at major system buses (such as large generating plant switchyards) and generally at or above 0.92 per unit at other system buses (with some possible exceptions for buses at the end of feeders). Also, the post-contingency voltage shall not vary more than 0.08 per unit from the pre-contingency voltage. For dynamic voltage related studies, one entity uses the criteria that the post contingency voltage recover to 0.90 per unit or more within one to three seconds following the disturbance.

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[287] SERC Supplement Transmission System Performance NERC Reliability Standards TPL-001 through 004: http://www.serc1.org/Documents/SERC%20Standing%20Committee%20Documents/Reference%20Documents/Procedures/Transmission%20System%20Performance%20SERC%20Procedure%20Rev%207%20(10-16-08).pdf.

[288] http://www.nerc.com/files/FAC-010-2.1.pdf.

[289] http://www.nerc.com/page.php?cid=2|20.

Most dynamic studies in the area include modeling the dynamic effects of induction motors via the use of PSSE models (such as the CLOAD complex load model and the CIM induction motor model) to identify potential problems. This methodology was performed within dynamic studies of the eastern North Carolina coastal area (Jacksonville/Havelock/Morehead City area). These coastal area studies resulted in a project to install a large static VAR compensator (SVC) at Jacksonville 230 kV substation, currently scheduled for completion by June, 2013. Duke Energy and Progress Energy completed a joint voltage stability analysis of their western NC transmission systems in spring 2011. This study shows that a minimum complement of generators will need to be on-line at various western area load/import levels to ensure adequate dynamic reactive resources are available. Another entity has noted that they are on schedule to install a SVC in the northern portion of their area to avoid reactive power issues and to mitigate possible voltage instability in that area under TPL Category C and D conditions. Guidance has been provided to operators on how to maintain stability until the SVC is in service. Overall, no stability or dynamics issues have been identified that will significantly impact reliability.

In addition to the installation of SVC technology in the area, entities are actively investigating potential application of "smart grid" technology. One entity is implementing a Distribution System Demand Response (DSDR) system that will be able to enhance reliability by providing controllable peak load reduction. By 2017, the system is expected to provide the ability to reduce peak demand by an incremental 247 MW for four to six hours at a time, which is the duration consistent with typical peak load periods. Approximately 100 MW of reduction has already been achieved. No other technologies are expected to be implemented on the system during the time period studied.

No reliability impacts are expected to occur from project delays or cancellations, or environmental regulations. Generally, before commitments to delay, defer or cancel projects are made, a careful review of the potential impacts resulting from the change from prior plans is conducted. This is generally the same process for impacts related to environmental regulations. As such, when changes are implemented, reliability impacts are known and are considered negligible once mitigated.

Demand

The 2011 summer aggregate Total Internal Demand forecast for the utilities in SERC-E is 43,249 MW and the forecast for 2021 is 49,640 MW (Table 104). The LTRA projections are based on average historical summer peak weather and are the sum of non-coincident forecast data reported by utilities in the area. This year's forecast compound annual growth rate (CAGR) for 2011 to 2021 is 1.26 percent. Due to the restructuring of the entity reporting footprints for this assessment, a comparison of demand forecasts is not available for this area. However, entities report that changes to forecasts reflect an economy that is expected to grow at a slower rate. These projections reflect increases in wholesale, retail, and customer growth. Overall, there are no significant changes in the forecast during this assessment period.

Table 104: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	43,249	49,640	6,391	1.26%	14.8%
Net Internal	41,554	47,400	5,846	1.20%	14.1%

Utilities in the reporting area use a variety of methods to forecast load. These may include economic and demographic assumptions, specific historical weather assumptions and the use of statistical simulations using multiple years of normal historical weather. Some assumptions may also include estimated demand and energy savings from future Energy Efficiency programs, as well as rate increases and potential carbon legislation impacts. Vendors such as Economy.com and IHS Global Insight were used for economic projections, and weather projections are taken from various sources such as the National Oceanic and Atmospheric Administration (NOAA) or individual company databases. One method uses three weather variables to forecast the summer peak demands. The variables are as follows:

- The sum of cooling degree hours from 1:00 p.m. – 5:00 p.m. during the summer peak day
- Minimum morning cooling degree hours per hour on the summer peak day
- Maximum cooling degree hours per hour on the day before the summer peak day

Economic projections can be obtained from Economy.com, an economic consulting Firm, and through the development of demand forecasts. Entities anticipated strong manufacturing industry recovery by the end of 2010; however, the non-manufacturing economy has not yet shown signs of recovery in the Carolinas. Forecasters are expecting this trend to continue in 2011.

A variety of programs that support Energy Efficiency and Demand Response are offered to customers in this Assessment Area (Table 105). Some of the programs are current energy-efficiency and DSM programs that include: interruptible capacity, load control curtailing programs, residential air conditioning direct loads, energy-efficient products loan programs, standby generator controls, residential time-of-use, Demand Response programs (interruptible and related rate structures), Power Manager Power Share Conservation programs,[290] residential Energy Star rates, Good Cents new home program, commercial Good Cents program, thermal storage cooling program, H20 Advantage water heater program, general service and industrial time-of-use, and hourly pricing for incremental load interruptible. These programs are used to reduce the affects of summer peaks and are considered part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced, energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event.

[290] http://www.duke-energy.com.

Table 105: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**277**	**1,152**	**875**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	611	1,156	545
Contractually Interruptible (Curtailable)	995	995	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	89	89	-
Total Dispatchable, Controllable Demand Response	**1,695**	**2,240**	**545**
Total Demand-Side Management	**1,972**	**3,392**	**1,420**

Measurements and verification (M&V) for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Conformity is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule. With the exception of NCUC guidelines stated in the Reliability Assessment Analysis section, entities within SERC-E have not adopted renewable portfolio standards for these resources.

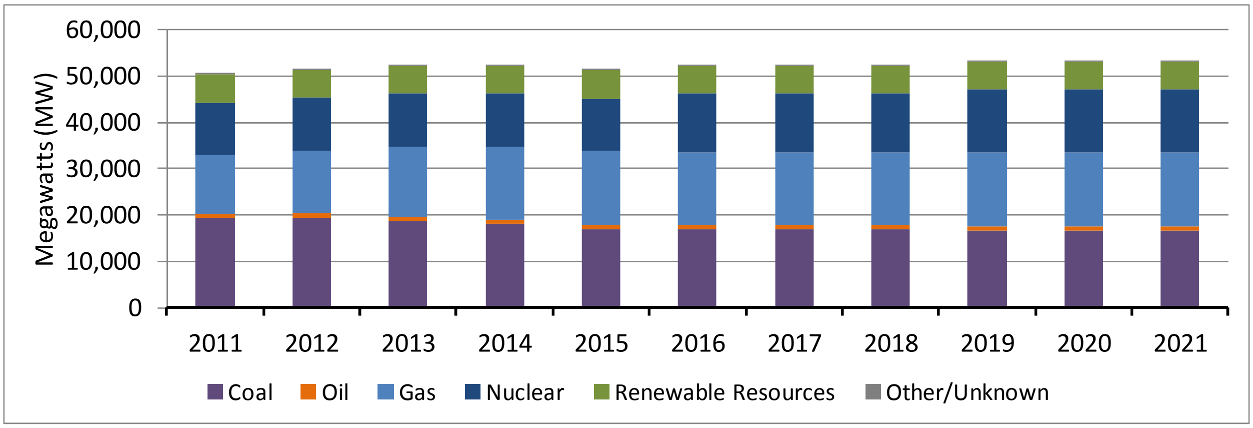
To assess demand variability, various assumptions are used to create forecasts. These assumptions are developed using economic models, historical weather (normal/extreme) conditions, energy use, and demographics. Entities continue to evaluate the inputs used in this process and track the actual parameters with the projections. Forecasts are based on an assessment of historical events that occurred over the previous 10-years as well as assumptions regarding the future. These assumptions relate to key factors known to influence energy use and peak demand (i.e., economic activity, price of electricity, weather conditions, and local area demographics). Non-weather sensitive industrial energy forecasts may be developed subjectively based on historical trends and information provided by individual industrial customers. Projections of peak demand are developed for the summer season and are based on equations that incorporate total energy requirements and long-term peak demand. In addition to the peak-demand base-case forecast, high and low-range scenarios are developed to address uncertainties regarding the future and extreme weather conditions.

Simulations for both energy and peak demand address the uncertainty associated with those factors and are included in econometric models. Results from the simulations are used to produce probabilistic high and low-range forecasts. Model inputs include probability distributions of total personal income, heating and cooling degree-days, and peak-day average temperatures. No major changes have been made to reflect the economic downturn. Outputs for each year of the forecast period include energy and peak demand distributions including projections from the 0 to 100.0 percent probability levels in increments of 5.0 percent. The high and low-range forecasts are represented by the 5th and 95th percentiles. Results provide peak demand estimates for given temperatures and the probabilities that peak demand will rise or fall to specific levels around the base case forecast. Daily load forecasts may be prepared by using software such as Neural Electric Load Forecaster (NELF), which takes into account daily temperature forecasts for service areas. Daily load forecasts are used to perform next-day studies and daily switching studies. No significant changes are reflected in this year's assumptions.

Generation

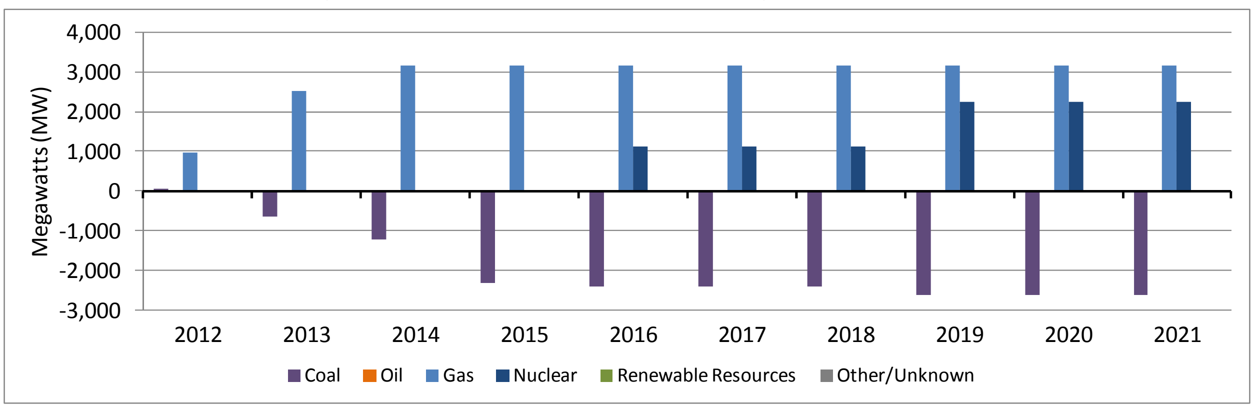
Projections for on-peak capacity mix by fuel type for the SERC-E Assessment Area are shown below (Figure 110).

Figure 110: On-Peak Capacity Mix by Fuel Type



SERC-E projected capacity additions are primary gas-fired with some additional nuclear resources returning to service by 2021 (Figure 110). Coal retirements are expected starting as soon as 2013.

Figure 111: Annual Net Capacity Change by Fuel Type



Companies within the reporting area expected to contribute to the aggregate capacity available on-peak (Table 106).[291] This capacity is expected to meet demand during this period. Variable capacity is not commonly planned in peak maximum capacity calculations. However, some entities evaluate these resources the same as all other generation resources. These resources may be given a reduced capacity contribution for Reserve Margin based on an estimated hourly energy profile.

[291] Poultry Waste Requirement (NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 42.0 percent).

Table 106: Companies Expected to Contribute to Aggregate Capacity

Overall Requirements and Timing	Additional Requirements	Solar Requirement (NC Only)	Hog Waste Requirement (NC Only)	Poultry Waste Requirement
3.0 % of 2011 load by 2012	Up to 25.0 % from Energy Efficiency through 2020	0.02 % by 2010	0.07 % by 2012	71,400 MWh by 2012
6.0 % of 2014 load by 2015	Up to 40.0 % from Energy Efficiency starting in 2021	0.07 % by 2012	0.14 % by 2015	294,000 MWh by 2013
10.0 % of 2017 load by 2018	Up to 25.0 % of the requirements can be met with Renewable Energy Certificates (RECs)	0.14 % by 2015	0.20 % by 2018	378,000 MWh by 2014
12.5 % of 2020 load by 2021	N/A	0.20 % by 2018	N/A	N/A

Renewable resource figures, including expected, rerated, and total nameplate capacity for SERC-E are included below (Table 107).

Table 107: Summer Renewable Resources On-Peak

	Renewable Resource	2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	-	-	-
	Derated	-	-	-
	Wind - Total Nameplate Capacity	**-**	**-**	**-**
Solar	Expected	16	16	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**16**	**16**	**-**
Hydro	Expected	3,006	3,006	-
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**3,006**	**3,006**	**-**
Biomass	Expected	21	21	-
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**21**	**21**	**-**

In order to identify the process used to select resources for reliability analysis/Reserve Margin calculations for future and *Conceptual* resources, resource planning departments within SERC-E use both quantitative analysis and qualitative analysis to meet customer energy needs in a reliable and economic manner. Quantitative analysis provides insight on future risks and uncertainties associated with fuel prices, load-growth rates, capital and operating costs, and other variables. Qualitative perspectives such as the importance of fuel diversity, the company environmental profile, the stage of technology deployment, and Regional economic development are also important factors to consider as long-term decisions regarding new resources. In light of the quantitative issues, several entities have developed a strategy to ensure that they can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

Other entity processes expect to secure resources needed further into the future through requests for proposals (RFPs) or designated network resources (backed by Firm resources). Future amounts of required reserves may be compared to the amount of current and planned generation on entity systems to gauge the need for future generating units. Others participate in reliability pricing model (RPM) capacity markets. *Conceptual* capacity is not counted until an Interconnection Service Agreement (ISA) is executed. All proposals for new capacity come through the Regional transmission expansion process to determine the required transmission expansion if necessary. Resources are evaluated using a wide range of criteria, including commercial availability, technical feasibility and cost.

Confidence factors are not commonly used to evaluate *Conceptual* resources. While some utility resource plans contain undesignated resources in future years, these undesignated resources may be supplied by new generation, purchases, uprates, DSM or a combination of these resources. Other entities use calculations of commercial probability. This method uses historically gathered information to assign probabilities to each milestone category (signed ISA, submitted, etc.). The probability percentages are then applied to the amount of queued resources in each category to determine a commercial probability for aggregate resources for each future year.

Other alternative processes define *Conceptual* resources by executed capacity agreements or by self-built generation within the approval stages for construction. Rigorous studies such as feasibility, system impact, and facility studies must be complete as part of interconnection processes before a resource can be categorized as *Conceptual*.

Capacity Transactions

Utilities within SERC-E reported the following imports and exports for this assessment period. All purchases are backed by Firm contracts for both generation and transmission (Table 108). Expected Firm imports during the summer amount to 1,318 MW in 2011 and drop slightly to 1,305 in 2021. Currently, there are no scheduled Exports in 2011, with 150 of Firm Exports projected for 2021.

Table 108: Seasonal On-Peak Capacity Transactions

Transaction Type		Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	1,318	1,305	1,582	1,305
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**1,318**	**1,305**	**1,582**	**1,305**
Exports	Firm	-	150	100	150
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**-**	**150**	**100**	**150**
	Net Transactions	**1,318**	**1,155**	**1,482**	**1,155**

Transmission

Delays with the in-service dates of certain projects have not been identified as a risk. In most instances, transmission projects planned to address a potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) issue receive the highest priority. If delays occur that result in reliability concerns, mitigation procedures would be developed. Mitigating measures could include re-dispatch of generation, operating procedures, and special protection schemes. On an ongoing basis, entities review/confirm project completion dates and monitor construction status of all transmission projects. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well-understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods. This should mitigate reliability concerns associated with line clearances and non-routine operating arrangements during higher seasonal load periods.

Additionally, no transmission constraints that will significantly impact reliability are expected to occur during the time period. Regional studies are performed on a routine basis both internally as well as externally. Coordinated single transfer capability studies with external utilities are performed quarterly through the SERC Near-Term Study Group (NTSG). Projected seasonal import and export capabilities are consistent with those identified in these assessments. Constraints external to the SERC Region are evaluated as part of the SERC East-RFC Seasonal Study Group efforts.

As described above, utilities in the reporting area have employed SVC technology in the past and expect to use this technology more in the future to maintain stability. One entity is also implementing a DSDR that will be able to enhance reliability by providing significant controllable peak load reduction in 2017. New technologies will continue to be explored as developments in research occur.

Operational Issues

Utility transmission planning departments within the reporting area have not identified any potential or systemic outages that may impact reliability during the next 10-years. Steps are taken to coordinate and complete scheduled generator maintenance ahead of peak demand periods. Recent studies take into account that existing generation is expected to be available during the peak demand periods and no transmission limitations are expected to occur. Daily reliability studies are also performed to ensure the transfer capabilities are sufficient to support external power flows across the transmission system.

In the event that peak demand is higher than forecast, some entities reported they would monitor activities at generating stations and defer elective maintenance that does not affect unit availability or capacity, but could pose a trip risk. Entities strive to meet customer energy demands either with available generating resources, power purchases, or with planned load-management programs. If customer demand cannot be met by these measures, emergency actions such as voltage reductions and manual load shed (as a last resort) are then used.

Entities report that they are not anticipating local environmental and/or regulatory restrictions that could potentially impact reliability. A careful review of the potential impacts resulting from the scheduled changes is performed before the implementation of any restrictions/regulations.

Since the amounts of distributed and variable generation are very small and entities within the reporting area hold a diverse amount of resources, special operating procedures are not needed for the integration of variable resources or to mitigate concerns resulting from high levels of Demand Response resources and distributed resource integration.

The utilities within SERC-E have procedures in place to identify and review misoperations caused by protection systems. When a misoperation occurs on the transmission system, corrective action is implemented to prevent recurrence. If needed, other locations are also reviewed for problems of a similar nature. Misoperations caused by protection systems are reviewed on an annual basis for possible trends.

Emerging and Standing Reliability Issues

Risk Assessment

The utilities in SERC-E area have identified an emerging issue in regard to Fault Induced Delayed Voltage Recovery (FIDVR) which is the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, sub-transmission, or distribution fault has been cleared. Significant load loss due to motor protective device action can result, as can significant loss of generation, with a potential secondary effect of high system voltage due to load loss. If the Bulk Electric System voltage does not recover to 90.0 percent of the pre-contingency system voltage in a few seconds, the FIDVR can initiate further tripping of load and generation. Longer periods of depressed voltage below such levels can cause damage to customer and electric system equipment.

FIDVR is caused by highly concentrated induction motor loads with constant torque, which stall in response to low voltages associated with system faults. This results in an excessive draw of reactive power from the grid. FIDVR events become increasingly probable with the increased penetration of low-inertia air conditioner loads that lack compressor undervoltage protection. FIDVR events can, and have, occurred following faults cleared in as few as three cycles.

Planning studies have not been able to foresee FIDVR events very accurately due to an inaccurate modeling of loads. Uncorrected, this modeling deficiency has a two-fold detrimental effect. First, it can result in studies that do not adequately identify potential FIDVR events. Second, it can give false confidence in mitigation plans designed to prevent FIDVR events. Several groups of experts are actively developing better dynamic load models for aggregate induction motor load, using results of extensive single-phase air conditioning performance tests, and detailing analyses of actual FIDVR events.

Although SERC-E has not experienced significant reliability impacts associated with FIDVR, some utilities in SERC-E plan to or have already installed SVCs as a mitigating measure for potential FIDVR issues.

Other Assessment Area-Specific Issues

To minimize reliability concerns on the system, entities regularly study and review annual and seasonal assessments. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Entities are also active participants within the SERC NTSG, which regularly performs annual reliability studies for summer and winter peak conditions as well as quarterly OASIS studies for summer, fall, winter, and spring conditions.

Transmission maintenance schedules are carefully reviewed and evaluated to insure reliability concerns are addressed, and to permit as much prioritized maintenance as can be accommodated prior to seasonal peak periods. Likewise, new construction efforts are focused on completing facilities ahead of seasonal peak periods. Annual planning activities continue to address both near- and long-term facility needs.

Assessment Area Description

SERC-E is a summer-peaking reporting area covering portions of two southeastern states (North Carolina and South Carolina.) with a population of approximately 13.9 million.[292] Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 58,900 square miles. There are five Balancing Authorities in SERC-E: Alcoa Power Generating, Inc – Yadkin Division, Duke Energy Carolinas, Progress Energy Carolinas, South Carolina Electric & Gas Company, and South Carolina Public Service Authority.

[292] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population

SERC-N

Introduction

SERC-N is a summer-peaking area covering most of Tennessee and Kentucky, northern Alabama, northeastern Mississippi, and small portions of Georgia, Iowa, Missouri, North Carolina, Oklahoma, and Virginia. There are six Balancing Authorities in SERC-N:

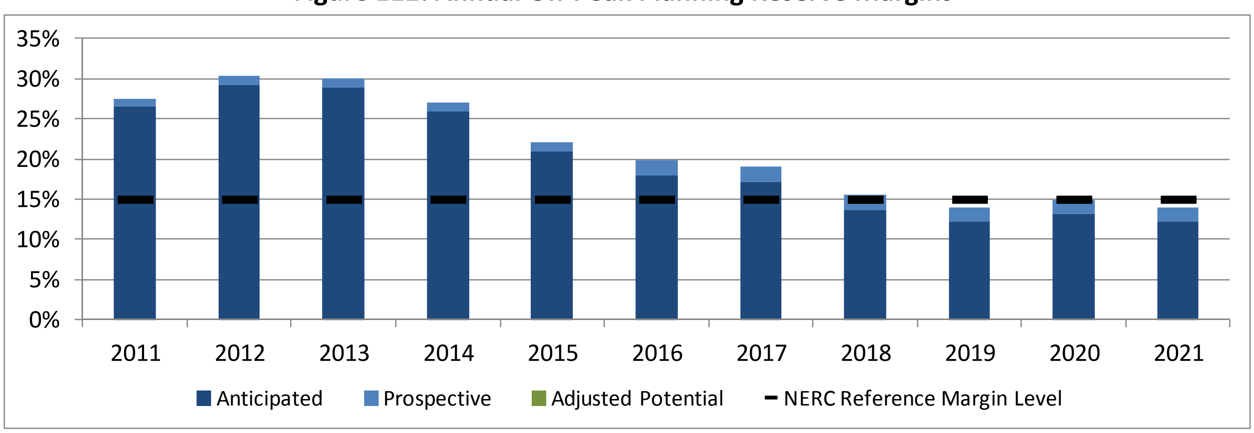
- Associated Electric Cooperative, Inc.
- Batesville Balancing Authority
- East Kentucky Power Cooperative
- Electric Energy, Inc., LG&E. and KU Services Company (as agent for Louisville Gas and Electric Company)
- Kentucky Utilities Company
- Tennessee Valley Authority

Reliability Assessment

The following sections provide aggregate 2011 summer peaking information supplied by SERC registered entities within this area to project the reliability of the Bulk Electric System for the assessment period.

Anticipated net-capacity resources Reserve Margins for utilities within SERC-N as reported from 2011 to 2021 are from 29.4 percent to 18.4 percent over the long-term period. There are no subregional, Regional, or state Reserve Margin requirements for this reporting area. However, margins are above the NERC Reference Margin Level of 15.0 percent (Figure 112). Individual entity criteria are based on the most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, weather uncertainty, economic growth, and loss-of-load probability studies (such as 1 day in 10-years).

Figure 112: Annual On-Peak Planning Reserve Margins



Resource adequacy studies are performed on a regular basis. Key variables within the studies are based on unit availability, import availability/capability, load forecast, and weather assumptions. The intent of these studies is to identify limitations or constraints that may impact seasonal adequacy, inform necessary decisions relative to resource acquisitions and project development timelines to maintain system reliability. Recent studies show that new capacity is needed, in 2017, to meet summer demand and maintain margins. However, entities do not anticipate problems maintaining reliability during this time period.

On average for the long-term period, 62,272 MW of internal resources and 1,734 MW of capacity transactions (which account for internal resources of non-reporting parties and for external resources) were reported during the time period. These resources are sufficient to meet the criteria or target Reserve Margin level for the 2011 summer and tighter in the latter part of the assessment.

Overall, utilities within the area are not relying on short-term outside purchases or transfers from other areas or Regions to meet demand requirements. To meet long-term demand needs, entities explore options to build capacity, use existing capacity by expanding current capacity, or contract for new capacity. The majority of the entities are members of reserve sharing groups with other neighboring entities such as PJM, Midwest ISO or the TEE Contingency Reserve Sharing Group (TCRSG). Both short- and long-term Reserve Margin requirements are treated similarly.

In order to mitigate the risk of fuel interruptions, the practices of having a diverse portfolio of suppliers, maintaining adequate supplies, and arranging for alternative delivery methods are common within the area. Fuel departments typically monitor supply conditions on a daily basis through review of receipts and coal burns. Any identifiable interruptions are assessed with regard to current and desired inventory levels. Coal inventories are set based on various risks including supply chain interruptions due to weather, vendor issues, and supply chain cycle times. Western coal deliveries are backed up by inventories at coal terminals. Fuel supplies are adequate and anticipated as being readily available for the assessment period. In the event of extended drought or forced outages, entities report that they will exercise options to make off-system purchases to meet demand, and these arrangements would be closely coordinated with the reliability coordinator.

Utilities in this area do not include energy-only or transmission-limited resources in their adequacy assessments. If entities see that resources are not available, they may plan on day-ahead and hourly spot-purchases as needed to make up for any shortfalls on the system. Additionally, the SERC-N reporting area has very little distributed generation and behind-the-meter generation and is not considered as part of capacity resources.

There are currently no RPSs or other mandates that impact variable renewable resources in resource adequacy processes. Some entities include small amounts of variable renewable resources in adequacy assessments based on historical experience. These resources are mixed with the dependable capacity values of those resources at the time of the system peak. Variable renewable resources from external entity systems may be treated like purchased power resources and are included only if Firm transmission service is available. If transmission service is Firm, the dependable capacity of these resources is based on the projected capacity value coincident with the system peak. In addition, there have been no recent changes to procedures that will ensure the operation of variable resources. Recent additions to TVA's renewable resources portfolio have primarily been in the form of purchased power contracts sourced from wind resources in the Midwest U.S. that pose no significant challenges to current planning procedures. As a hedge against applying too much capacity credit for intermittent resources, on-peak impacts from those sources are adjusted to reflect net dependable capacity values to reduce the contribution to resource adequacy calculations and maintain a sufficient level of reliability. Entities continue to evaluate the potential to add renewable resources to the portfolio through integrated resource planning studies. The outcome of these studies may prompt a revision to adequacy assessment procedures in the future.

Demand Response is considered in various ways in resource adequacy assessments. Programs that are considered include interruptible and direct load control programs. These programs create a load reduction and, therefore, impact reserves carried on the system. Other entities include the contribution of Demand Response programs in their long-range capacity planning studies based on analysis of the particular program impacts, historical trends of Demand Response effectiveness, and system cost-effectiveness criteria. This analysis helps to set a dependable capacity value of Demand Response for use in summer-peak adequacy assessments. Scenario planning is also employed to evaluate the impact on system reliability for differing assumptions of Demand Response effectiveness.

At least 2,100 MW will be retired on the TVA system in the next 6 years. TVA will shut down 18 coal boilers at 3 power plants: 10 at Johnsonville, in Waverly, TN; 6 at Widows Creek, along the Guntersville Reservoir; and 2 at John Sevier, near Rogersville, TN.[293] Scenario-planning studies have been performed to assess the impact on system reliability and adequacy for various assumptions of other possible unit retirements that might occur during the planning window, and alternatives are being considered to maintain system reliability.

No additional UVLS schemes are planned for installation during the assessment period. TVA has UVLS protection schemes installed in two areas of their system for the purpose of limiting a potential wider area under-voltage event. The non-coincident peak demand served from the substations equipped with UVLS totals approximately 450 MW. Additionally, no SPSs or RASs are planned for the time period.

Currently, entities have plans to regularly participate in emergency system drills to ensure that operators are trained and properly prepared for catastrophic events. The transmission planning processes prepare for the loss of up to all units at any given generating station as part of seasonal assessments. Planners disseminate that information to system operations. Entities also rely on reserve sharing, Purchasing and Selling Entities (PSEs) and coordination with Balancing Authorities through capacity and energy emergency plans. Planned unit maintenance outages or derates may be delayed or canceled in the event of a significant loss in capacity. If these efforts are not sufficient, then voluntary load shedding and energy emergency criteria will be enacted.

Some entities use risk analysis and stochastic processes to identify the contingencies that have the greatest impact on their resource adequacy over the long-term. Specific outage events are not modeled in that analysis, but may be considered during sensitivity studies as part of the annual capacity planning

[293] http://www.wrcbtv.com/Global/story.asp?S=14446684.

effort. If resource inadequacies (such as catastrophic events) cause the Reserve Margin to be reduced, the entity then anticipates the use of purchases from the short-term markets as a necessary addition to appropriate operational actions to ensure system reliability.

Companies in the area maintain individual criteria to address any problems with stability issues. Recent study results reported the need for capacitor and transformer projects to address local voltage concerns. Other study results did not detect any issues that were not mitigated by existing operating guides. Utilities employ P-V and Q-V study[294] methodologies to assess dynamic reactive margins.

Voltage stability margins are also implemented by utilities on an individual basis. Utilities generally follow the procedure of making sure that the steady-state operating point is at least 5.0 percent below the voltage collapse point at all times to maintain voltage stability. Others follow the criteria that generator interconnections must recover to 0.9 p.u. voltages within one second after the fault has cleared. Studies are performed on-peak-demand cases to verify system stability margins. Other utilities follow guidelines to ensure that voltage stability will be maintained via P-V and Q-V analysis.[295]

New systems, tools and technologies continue to be evaluated and considered to improve Bulk Electric System reliability. The most recent improvements consist of conventional technologies (*i.e.,* reconductoring, capacitor additions, etc.). Deployment of "smart grid" technologies is being assessed in consultation with TVA power distributors. Most efforts to date have only been on the scale of demonstration projects. A summary of TVA's current research and programs can be found on TVA's web site.[296] LG&E and KU Energy plan to invest approximately $14 million in Smart Grid, between 2011 and 2014. These investments provide for a variety of enhanced capabilities for system monitoring and operation. However, no reliability improvements or issues have been identified as a direct result of these investments.

As described above, entities in the area are planning for several unit retirements in order to address environmental regulations. Other entities are anticipating impacts from new regulations (*e.g.,* greenhouse gas regulations, electric utility hazardous air pollutant "MACT" regulations, effluent guidelines for electric utilities, etc.). However, as with every regulation that is issued, companies will continue to adapt their operations, as needed (*e.g.,* install controls, etc.), to comply with the new regulatory requirements and not affect reliability.

Although the area has experienced the effects from a slowed economy, entities report that they have not experienced any Bulk Electric System project slow-downs, deferrals, or cancellations that may impact reliability.

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[294] Q-V analysis is a common graphical analysis used to measure voltage stability at load buses by observations in the Variations of VARs and MWs. This method is used to help utilities define measurements of stable operation and measure instability in the event of a disturbance on the system: http://eeeic.eu/proc/papers/11.pdf.

[295] Ibid.

[296] http://www.tva.gov/environment/technology/epri.htm.

Demand

The 2011 summer aggregate Total Internal Demand forecast for the utilities within SERC-N is 46,846 MW and the forecast for 2021 is 52,189 MW. The LTRA projections are based on average historical summer peak weather and are the sum of non-coincident forecast data reported by utilities in the area. The average annual growth rate between 2011 and 2021 is 0.99 percent (Table 109). Due to the restructuring of the entity-reporting footprints for this assessment, a comparison of demand forecasts is not available for this area. However, entities report minimal change in growth since last year's assessment.

Table 109: On-peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	46,846	52,189	5,343	0.99%	11.4%
Net Internal	44,931	48,495	3,564	0.70%	7.9%

The 2011 to 2021 demand forecast is based on normal weather conditions and economic data for the reporting area population, forecast demographics for the area, employment, energy exports, and gross regional product increases and decreases. A range forecast is then developed for extreme and mild weather scenarios for both optimistic and pessimistic economic conditions.

As with other reporting areas in SERC, strong emphasis is placed on Energy Efficiency. The following energy-efficiency programs are offered across the residential, commercial, and industrial markets:

- *New Homes*: Promotes all-electric, energy-efficient new homes. All homes built must meet a minimum rating in overall Energy Efficiency.
- *Heat Pumps*: Promotes the installation of high-efficiency heat pumps in homes and small businesses.
- *New Manufactured Homes*: Promotes the installation of high-efficiency 13 SEER[297] heat pumps in new manufactured homes and currently has over 40.0 percent of the market share in the Valley.
- *Do-It-Yourself Home Energy Evaluation*: This program allows homeowners to receive a free energy-efficiency kit from TVA after completing an online or paper home-energy survey. Residents also receive personalized reports on their home's annual energy use and energy-saving recommendations.
- *In-Home Energy Evaluation Program*: This program offers financing options and incentives to help homeowners make investments in significant energy-efficiency improvements identified through onsite evaluation by an energy-efficiency professional.
- *Commercial Efficiency Advice and Incentives Program*: This program offers businesses an opportunity to receive an energy assessment of their facilities to help them identify energy-saving opportunities. Financial incentives are also available for projects that help reduce power consumption during TVA's peak period.

[297] Definition for SEER: http://www.inspectapedia.com/aircond/aircond04.htm.

- Major Industrial Program: This program encourages reductions in electric-energy intensity in large industrial facilities that have a contract demand greater than five MW. Financial incentives are available for projects' resulting in reductions during TVA's peak period.
- EKPC programs:
- Energy Audits: providing expert help to save energy and lower bills
- CFL bulbs: EKPC is giving away more than 440,000 energy-efficient bulbs
- Envision Energy Services: providing assistance for business members
- Touchstone Energy Homes: helping to build new energy-efficient houses[298]
- Button-up Program: plugging leaks in homes' heating and cooling systems
- Tune-up program: maximizing heating/cooling efficiency
- Manufactured Home program: helping to increase efficiency
- Simple Savings program: educating homeowners about quick, easy fixes
- Direct Load Management: saving money by shaving power use
- Real-Time Pricing: providing information to make smart choices[299]

Additional programs include: low income weatherization, commercial Conservation, residential HVAC maintenance, small business lighting, commercial building recommissioning, and prescriptive energy-efficient equipment incentives for industrial and commercial end-users.

Program results are verified in a variety of ways:

- Residential programs involving financing/incentives receive installation verification inspections
- Residential online energy evaluations receive follow-up surveys on a sample basis to determine actions taken
- Commercial programs receive post installation inspections/measurements to determine savings
- Third-party evaluations for M&V purposes at various intervals.

The primary sources of Demand Response are interruptible product portfolios, which include all companies that have contractually agreed to reduce their loads within minutes of a request. Products that use control devices (50,000 switches to be installed by 2017), commercial Conservation, lighting programs, dynamic voltage regulation and direct load control of water heaters and air-conditioners are also used by entities within SERC-N on: air conditioning, water heaters, and Conservation voltage regulation of distribution feeders. Measurement and verification of the current Demand Response aggregation effort is achieved through near-real-time metering of the individual sites under contract to track their actual response to each called event (Table 110). Entities within this area do not have renewable portfolio standards with which they must comply. Therefore, these resources are not considered for this purpose.

[298] http://www.greenworks.coop/energyefficiency.html.

[299] Ibid: http://www.greenworks.coop/renewableenergy.html.

Table 110: On-Peak Energy Efficiency and Demand-Side Management

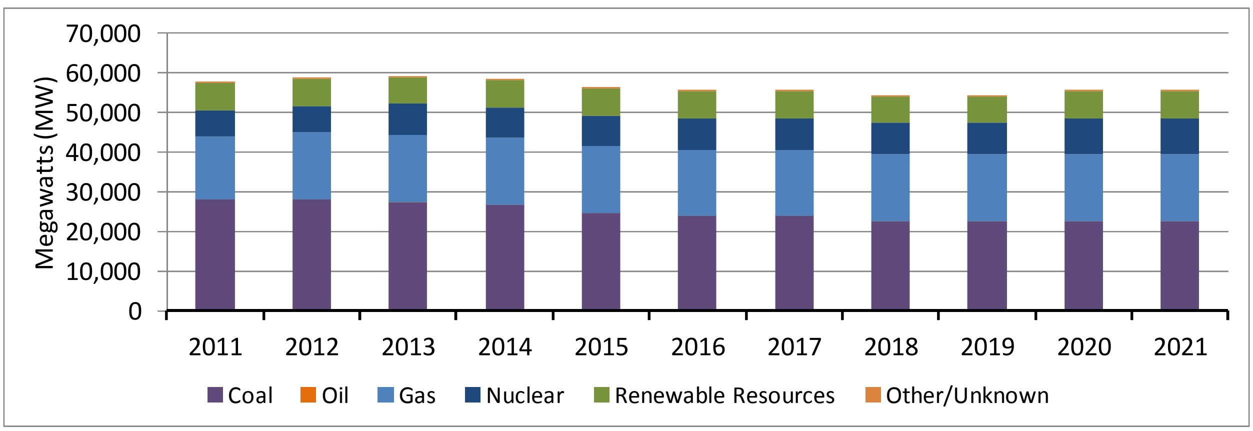
Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**277**	**1,152**	**875**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	611	1,156	545
Contractually Interruptible (Curtailable)	995	995	-
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	89	89	-
Total Dispatchable, Controllable Demand Response	**1,695**	**2,240**	**545**
Total Demand-Side Management	**1,972**	**3,392**	**1,420**

To assess variability, utilities use the demand forecast assumptions mentioned above to develop models for extreme peaks and demand models to predict variance. Models take into consideration extreme temperatures, economic concerns and price uncertainty. No significant changes to forecasting methods have been reported for the assessment period.

Generation

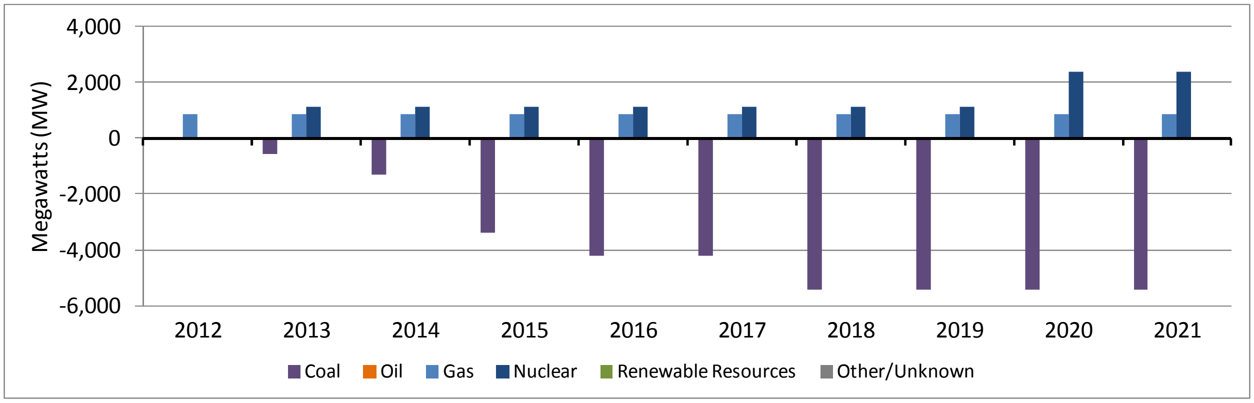
Utilities in SERC-N expect to have a diverse on-peak capacity mix (Figure 113).

Figure 113: On-Peak Capacity Mix by Fuel Type



Additional gas resources and nuclear resources are expected to come on-line while coal resources are projected to retire, especially between 2014 and 2017 (Figure 114).

Figure 114: Annual Net Capacity Change by Fuel Type



Most entities in the area do not have any biomass or variable resources that are included in the expected on-peak capacity amount. However, some have purchases sourced from wind generation that are included in the transfer amount, and a small amount of solar supply that is part of a customer-owned generation buy-back program. The amount of solar is very small and is not considered as capacity. The capacity value of those wind contracts is based on applicable contract terms, and the assumed contribution at the time of the system peak is computed by applying a 12.0 percent capacity credit factor to the nameplate ratings of the associated wind generators. This factor is consistent with the credit applied by Regional Transmission Organizations (RTOs) to other wind resources in that same geographical area. The contribution from the customer-owned solar resources is based on the insolation values at the time of the summer peak. Entities will continue to evaluate these and other renewable resources as part of their integrated resource planning processes. Related renewable resource figures in SERC-N are shown below (Table 111).

Table 111: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	152	152	-
	Derated	132	132	-
	Wind - Total Nameplate Capacity	**284**	**284**	**-**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	5,033	5,033	-
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**5,033**	**5,033**	**-**
Biomass	Expected	17	17	-
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**17**	**17**	**-**

For reliability analysis/Reserve Margin calculations, entities within this reporting area take into account existing resources and may use an RFP process for forward capacity markets or use Firm contract purchases (both generation and transmission) toward Firm capacity. Most entities in the reporting area do not apply a confidence factor to *Conceptual* resources. Instead, entities may use risk analysis and scenario planning studies to identify potential resource adequacy issues. Resource adequacy may be assessed both with and without *Conceptual* resources to identify the magnitude of risk exposure and the lead time needed to ensure the necessary commitments to acquire or construct resources to maintain reliability. Short-term capacity planning (three to five years out) is used to focus on market options that might be available to replace *Conceptual* resources identified by long-range capacity expansion planning studies. Finally, the SERC-E Assessment Area has very little distributed generation or behind the meter generation and it is not considered as part of capacity resources.

Capacity Transactions

Utilities within SERC-N reported the following imports and exports for this assessment period (Table 112). Expected Firm imports for the summer drop from 1,449 MW in 2011 to 932 MW in 2021. Similarly, Firm exports drop from 1,093 MW in 2011 to 417 MW in 2021. The majority of these imports/exports are backed by Firm contracts for both generation and transmission. It was not reported if import assumptions are based on partial path reservations. These reports have been included in the aggregate Reserve Margin for utilities in the reporting area.

Table 112: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	1,449	932	1,611	935
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**1,449**	**932**	**1,611**	**935**
Exports	Firm	1,093	417	1,141	417
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**1,093**	**417**	**1,141**	**417**
	Net Transactions	**356**	**515**	**470**	**518**

Transmission

The majority of the projects reported are load-serving in nature, with the goal of maintaining reliable service throughout the planning horizon. There are currently no concerns in achieving expected in-service dates. Constraints and delays would be handled through entity emergency or other operating procedures. System conditions may at times dictate local area generation re-dispatch or reconfiguration of transmission elements to alleviate anticipated next-contingency overloads. NERC TLR procedures are also a temporary option in resolving scenarios that are not easily remedied by a local area solution.

As described in the previous sections, entities within SERC-N continue to evaluate and consider new technologies that can be used to improve Bulk Electric System reliability. Currently, the most recent improvements consist of conventional technologies (*i.e.,* reconductoring, capacitor additions, etc.). The deployment of Smart Grid technologies is being implemented and assessed in consultation with power distributors in the area. Multi-million dollar investments in this technology are expected to occur from 2011 to 2014.

Operational Issues

Other than scheduled individual planned outages, there are no existing or potential systemic outages that negatively impact reliability anticipated within SERC-N during the assessment period.

To address operational measures that are available if peak demands are higher than forecast, utilities within the reporting area perform studies based on both normal and extreme projected peak conditions. Monthly, weekly, and daily operational planning efforts take demand and unit availability into consideration. This helps to address any inadequacies and mitigate their risks. Entities also expect to use various operational measures during unexpected high peak demands. Some of these measures are day-ahead and hourly spot purchases, interruptible load, and DSM measures. Entities might also consider issuing Energy Emergency Alerts (EEAs) as an option to free up Available Transmission Capacity (ATC) in order to import more power onto the system. As a last-step measure, entities have the ability to shed Firm load to maintain the integrity of the interconnected power system. Various emergency operations plans, processes and procedures are in place to ensure balance from resource-to-load and reserve obligations.

Future environmental or regulatory restrictions were previously addressed in the Reliability Assessment section. As entities are made aware of any long-term system changes (including fossil plant retirements), the impacts will be studied and transmission plans will be developed or refined to maintain the reliability on the system in accordance to applicable criteria and the NERC Reliability Standards. The majority of the entities within the reporting area have no integrated variable resources on their systems, and wind contracts in place for the assessment period are not anticipated to be significant enough to cause operational changes or concerns. Also, due to limited Demand Response in the reporting area, reliability concerns from high levels of Demand Response resources are not a concern.

A formal program with multiple goals has been established to minimize the likelihood of relay protection misoperations. Recognized problem areas include an increase in 'unknown' causes, carrier failure, calculations and settings applications, and relay design applications. Remedial measures include a maintenance program to periodically calibrate and test relays, investigation of every relay misoperation, a goal to remedy misoperations within two years, a relay replacement program to replace obsolete relays, improved implementation processes, and improved identification of mutual coupling effects.

Emerging and Standing Reliability Issues

Risk Assessment

Utilities within the SERC-N reporting area have identified two reliability issues; weather-related disasters, and reconstruction efforts underway due to historic levels of tornadic activity in the southeastern U.S. in April 2011. While weather-related disasters are a standing issue for the SERC-N reporting area, the reconstruction efforts are an emerging issue following the recent storm damage. No long-term reliability impacts are expected due to the storm damage from the spring storms. The assessment impacts are generally the same for both reliability issues.

Weather-related disasters have an immediate operational impact followed by varying ranges of reconstruction activities. Resource adequacy, transmission adequacy, and operations are impacted in the event of weather-related disasters such as tornados, ice storms, and flooding, and can limit operation and fuel supplies of resources. Deliverability of resources can also be limited.

Extreme weather events are sporadic in nature, and experiencing two or more such events can lead to uncertainty in the ability to maintain adequate reserves. The unprecedented April 2011 storm events in the southeastern U.S. damaged approximately 90 TVA transmission lines, which resulted in their removal from service. Widespread damage can challenge entity reserves of restoration materials. Utilities within the reporting area have come under pressure regarding maintaining margin reserves due to current restoration activities, maintenance schedules, high-water threats from the Mississippi River, and hot weather patterns. TVA has started cutting back on some industrial customers covered by contracts allowing curtailment during periods of heavy demand.

Maintaining formalized procedures, processes, and personnel training help ensure that impacts of weather related disasters are minimized.

Assessment Area Description

SERC-N is a summer-peaking reporting area covering all or portions of 10 states (Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia) with a population of approximately 27.6 million.[300] Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 101,000 square miles. There are six Balancing Authorities in SERC-N: Associated Electric Cooperative, Inc., Batesville Balancing Authority, East Kentucky Power Cooperative, Electric Energy, Inc., LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company, and Tennessee Valley Authority.

[300] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population.

SERC-SE

Introduction

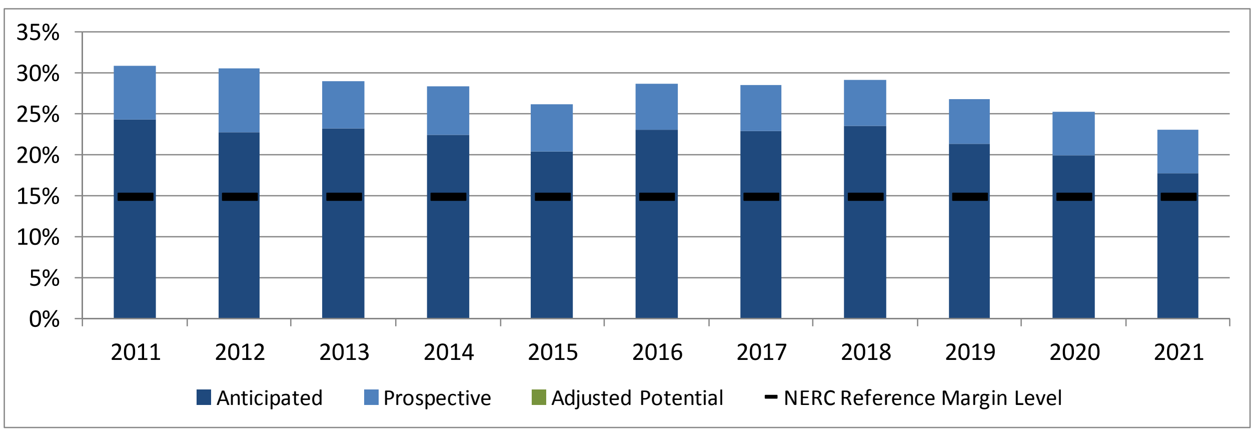
SERC-SE is a summer-peaking reporting area covering portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida). This reporting area consists of four Balancing Authorities identified as:

- PowerSouth Energy Cooperative
- South Mississippi Electric Power Association
- Southeastern Power Administration
- Southern Company Services, Inc.

Reliability Assessment

Projected net Reserve Margins for utilities within SERC-SE from 2011 to 2021 are from 24.3 percent to 17.8 percent over the long-term assessment period (Figure 115). There are no subregional, Regional, or state Reserve Margin requirements for this reporting area, other than mandated margins from the State of Georgia. The State of Georgia requires maintaining Reserve Margins of at least 13.5 percent near-term (less than 4 years) and 15.0 percent long-term (4 years or more) for investor-owned utilities. Most entities use a target of 15.0 percent to ensure reliability, and current calculations indicate projected Reserve Margins remain well above this target.

Figure 115: Annual On-Peak Planning Reserve Margins



The target percentage, in most entity procedures, is not adjusted for near- or long-term margins. Entities that treat near- and long-term margins differently adjust load forecasting errors separately for near- and long-term planning studies. Recent analyses of load forecasts indicate that expected Reserve Margins remain well above 15.0 percent for the next several years. Analyses account for planned generation additions, retirements, deratings due to environmental control additions, load deviations, weather uncertainties, forced outages, and other factors.

Resource adequacy is determined by extensive analysis of costs associated with expected unserved energy, market purchases and new capacity. These costs are balanced to identify a minimum cost point that is the optimum Reserve Margin level. Resource adequacy studies are evaluated, on a regular basis, to assess future resource needs. Entities update integrated resource plans on a yearly basis by modifying load forecasts, outage information, fuel costs, and other inputs as needed. These assessments are usually performed for the current year through a 20-year planning horizon. Sensitivities addressing criteria such as impacts expected from future environmental standards or law are evaluated as needed.

For this assessment period, on average, SERC-SE utilities reported 71,175.9 MW of potential capacity resources. These resources are considered to be able to meet the criteria or target Reserve Margin levels for the period.

One entity within SERC shares contractual rights to the generation of a facility in the FRCC Region. The entity within SERC-SE has the rights to approximately 150 MW of power during the summer and has Firm transmission service to import it; however, it is not relied upon to meet its Reserve Margin targets.

SERC-SE has minimal distributed generation or behind-the-meter generation and this is not considered in meeting Reserve Margin targets. Additionally, Energy-Only resources and transmission-limited resources are not commonly included in SERC-SE Reserve Margin calculations, or in resource adequacy assessments.

The fuel supply infrastructure, delivery system, and reserves are all adequate to meet peak gas demand and avoid possible interruptions. In the case of a possible interruption, entities report that they have Firm transportation diversity, gas storage, Firm pipeline capacity, and on-site fuel oil and coal supplies to meet the peak demand. The utilities have a highly diverse fuel mix to supply the demand, including nuclear, Powder River Basin coal, eastern coal, natural gas and hydro. Some utilities have implemented fuel storage and coal Conservation programs, and various fuel policies to address any supply interruption concerns. Entity fuel supply policies ensure that storages are filled well in advance of the start of hurricane season (June 1) of each year. These tactics along with additional power purchases help to ensure balance and flexibility to serve anticipated generation needs. The relationships and communication between coal mines, coal suppliers, railroads, coal plants, and other energy suppliers ensure that fuel deliveries occur as scheduled. Potential problems are communicated well in advance to enable adequate response time.

RPSs are not commonly implemented or mandated within the reporting area, but companies continue to evaluate many types of resources, including renewable resources. Biomass, in the form of landfill gas and wood waste, has been introduced in limited quantities. Companies are pursuing the installation of new facilities and the conversion of existing facilities to burn biomass products, but do not consider such resources to be variable. The performances of these plants are contractually required to perform similarly to that of a coal plant, and therefore new biomass-burning resources are included in resource adequacy studies at their designed ratings.

Variable resources, such as wind and solar, are not considered in resource adequacy studies due to their inherently non-Firm characteristics. In addition, no significant amounts of these types of resources are currently installed or projected to be installed on the system in this area. Therefore, no planning approaches/changes have been needed or developed to ensure reliable integration and operation of such resources.

Most utilities in the reporting area do not include Demand Response effects in their resource adequacy assessments, but those that do consider them include these programs in several ways. Real-time pricing (RTP) load response was reported to be divided into two categories: standard and extreme. Standard RTP by historical observation is that load which is expected to be reduced at weather-normal peaking-price levels, and is deducted from the peak demand in the resource adequacy analysis. Extreme RTP is expected to reduce at higher pricing levels than expected for the standard RTP and is subdivided into separate blocks, each having an amount and a price trigger determined by analysis. The capacity equivalent, relative to the benefit of a combustion turbine, of Extreme RTP is included in the resource analysis as a capacity resource. Interruptible load is evaluated to determine its capacity equivalent, based on the contract criteria, relative to the benefit of a combustion turbine. The resulting value is included in the resource analysis as a capacity resource limited by the contract callable terms: hours per day, days per week, and hours per year.

The current integrated resource plans contain no significant unit retirements. However, entities continue to evaluate reliability impacts of potential EPA regulations and climate legislation. The effects of EPA regulations or legislative decisions may result in the unavailability of significant amounts of existing generation, and the ability to procure and construct replacement generation within a given timeframe could present a reliability concern. Entities are working through solutions in order to address potential unit retirements that may occur.

Fossil generating units in the Southern Company Balancing Authority have operating limits related to air and/or water quality, derived from both Federal and state regulations. A number of these units have unique limits on operations and/or emissions; some are annual limits while others are seasonal. These restrictions are continually managed in the daily operation of the system while maintaining reliability. Similarly, hydroelectric units are run in cooperation with the U.S. Army Corps of Engineers to maintain water levels and river flow, as well as system reliability. Overall, no existing conditions are projected to impact the reliability on the Bulk Electric System because of environmental restrictions.

A nominal 2,250 MW UVLS scheme has been installed in north Georgia. The scheme was installed to help meet three-phase faults with breaker failure contingencies. Plans to install more schemes have not been reported for the period. A Remedial Action Scheme will be installed in 2012, to resolve a minor contingency overload of a 115 kV line. The entity plans to address the loading issue by reconductoring a section of the line in 2013.

Utilities within the reporting area use various tactics to prepare for catastrophic events. Processes and guidelines for coal, natural gas, and transmission use are areas that companies have seen to be most critical. To address the coal concerns, several resource adequacy studies were conducted to evaluate the ability to meet peak demand while considering the historic and probabilistic limitations of import interfaces. Additionally, a special scenario study was performed to assess the ability of the system to sustain a credible, worst-case catastrophic natural gas pipeline failure event. The results of this study were used to assess reliability exposure and determine the benefit of retrofitting oil backup capability to an existing combined cycle unit. Natural gas is assessed by some utilities through Firm gas supply contracts with over 25 natural gas suppliers from multiple Regions, including the Gulf of Mexico, mid-continent, and LNG. In addition, over 100 NAESB[301] contracts with suppliers and contracts with natural gas storage service providers ensure protection against short-term supply interruptions. The gas pipeline companies and gas storage providers communicate any facility outages or issues in advance through informational postings on their web sites or through e-mail.

As described above, companies in the SERC-SE area also regularly perform transmission studies considering the loss-of-pipeline, extreme event (TPL-003 and 004), and infrastructure security. Various contracts (master interchange and reserve sharing agreements, interruptible load contracts, Reserve Margins, dual fuel capabilities, etc.) are currently in place to provide assistance during emergency conditions. Their purpose is to address vulnerability to catastrophic events and then foster 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.

Transmission planning studies within the area consists of near- and long-term regional and local area studies. Reliability concerns identified in the studies include thermal overloads and voltage problems. These concerns are addressed through the development of projects, to correct the thermal and voltage problems for this long-term assessment period. Study methodologies in place are designed to meet the TPL 001-004 standards, as well as seasonal assessments which are performed prior to the upcoming season with known outages and dispatch levels. Methodologies evaluate single, multiple, and extreme contingencies as defined in the NERC Reliability Standards. In the event that a facility exceeds its applicable rating, either an operating solution or a transmission enhancement is identified to address the reliability issue. These enhancements generally include upgrades, reconductoring/rebuilds, and/or new transmission lines. Entities report that 10-year assessments recently performed did not identify any issues that could not be mitigated with appropriate actions.

There are no subregional criteria for dynamic, voltage, or small signal stability within SERC-SE; however, various utilities perform individual studies and maintain individual criteria to address stability issues. A criterion such as voltage security margins of 5.0 percent or greater (in MW) has been used within various utility practices. To demonstrate this margin, the powerflow case must be voltage stable for a 5.0 percent increase in demand (or interface transfer) over the initial demand in the area (or interface) under study with planning contingencies applied. Studies are performed each year for the upcoming summer, and generally for a future year case. Entities did not indicate any issues that would impact reliability during the period. Other utilities use an acceptable voltage range of 0.95 p.u. to 1.05 p.u. on their transmission system. During a contingency event, the lower limit decreases to 0.92 p.u. with the upper limit remaining the same. The acceptable voltage range is maintained on the system by dispatching reactive generating resources and by employing shunt capacitors at various locations on the system.

[301] North American Energy Standards Board

To address dynamic reactive criterion, some utilities follow the practice of having a sufficient amount of generation on-line to ensure that no bus voltage is expected to be subjected to a delayed voltage recovery following the transmission system being subjected to a worst-case, normally cleared fault. Studies involve modeling half of the area load as small motor load in the dynamics model. Prior to each summer, an operating study is performed to quantify the impact of generating units in preventing voltage collapse following a worst-case, normally cleared fault. The generators are assigned points, and the system must be operated with a certain number of points on-line depending on the current system conditions, such as the amount of load on-line and the current transmission system configuration. The study is performed over a range of loads from 105.0 percent of peak summer load down to approximately 82.0 percent of peak summer load conditions.

Companies within the reporting area also have performed dynamics studies to evaluate the reactive power capability that equipment is required to supply to the transmission system. Through this study, entities found potential FIDVR challenged situations within the area. Results were used to determine system improvements, including reactive power sources to avoid possible voltage collapse in the metro Atlanta area. Air quality concerns result in Atlanta load being served mainly from remote generation resources. This has led to the installation of equipment to provide dynamic VARs that are only injected into the system when the voltage dips below 85.0 percent of nominal. A study of the upcoming summer is performed each year to provide system operators guidance on how to insure that enough dynamic VARs are available to keep the system secure. Studies of future years have also identified needed capital improvements which will be put into future budgets.

New technologies, systems, or tools have not been added to the system since the last assessment. However, utilities within the reporting area are using many smart grid technologies and related applications. Smart grid investments have been made over many years to help maintain reliability. Some of these technologies enable the grid to communicate potential problems to minimize disturbances. Others have the ability to take corrective action, such as restoring service quickly to customers who are not directly affected. Yet other devices provide system operators with the real-time information and diagnostic tools needed for rapid decision making, allowing utilities to avoid outages or minimize their impact. Utilities continue to explore the viability of new technologies to continue to expand the use of intelligent electronic devices for monitoring system conditions, improved reliability, and optimum performance.

The state of the economy has resulted in much lower load forecasts, which may delay the need for certain generation/transmission projects. However, the effects of any generation/transmission project slow-downs, deferrals, or cancellations should not negatively impact reliability. As mentioned above, several of the proposed climate legislations or anticipated EPA regulations could lead to potential unit retirements in the planning horizon. Entities continue to evaluate reliability impacts of these concerns, and solutions are being developed to address them. Overall, this is currently not seen as a reliability concern. However, if the impact of legislation and regulation results in the inability to distribute significant amounts of existing generation across the Southeast, then the ability to procure and/or construct replacement generation within a given timeframe could present a reliability concern.

Demand

The 2011 summer aggregate Total Internal Demand forecast for the utilities within SERC-SE is 49,314 MW and the forecast for 2021 is 58,359 MW (Table 113). The LTRA projections are based on average historical summer peak weather and are the sum of non-coincident forecast data reported by utilities in the area. This assessment's CAGR projection for Total Internal Demand between 2011 and 2021 indicates a 1.54 percent average annual growth rate. Due to the restructuring of entity reporting footprints for this assessment, a comparison of demand forecasts to previous values is not available. Entities report that changes in their individual growth rates reflect the conditions of a slowed economy, as well as recovery efforts from the economic downturn.

Table 113: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	49,314	58,359	9,045	1.54%	18.3%
Net Internal	47,610	56,042	8,432	1.49%	17.7%

Peak demand forecast is commonly based on average historical normal weather assumptions, load growth and conservative economic scenarios. Assumptions from regressing demographics, specific historical weather and demand assumptions, or the use of a Monte Carlo simulation using multiple years' of historical weather are also commonly used. Vendors such as Economy.com and IHS Global Insight were used for economic projections, while weather projections were taken from various sources such as the National Oceanic and Atmospheric Administration or individual company databases. Estimated demand and energy savings from future Energy Efficiency and Demand Response programs are also accounted for in the forecast, as well as rate increase impacts and potential carbon legislation impacts. Overall, assumptions for this period reflect modest declines in the long-term relative to historic levels.

Various utilities within SERC-SE have residential energy-efficiency programs that may include educational presentations, residential energy audits, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, energy-efficient new-home programs, Energy Star appliance promotions, loans or financing options, weatherization, programmable thermostats, and ceiling insulation. Commercial programs may include energy audits, lighting programs, and plan review services.

Other programs such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits, and comfort advantage energy-efficient home programs promote reduced energy use, supply information, and develop energy-efficiency presentations for various customers and organizations. Utilities within SERC-SE are also beginning to work with states' energy divisions on energy-efficiency planning efforts. Training seminars addressing Energy Efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

Demand Response programs within the reporting area range from real-time pricing/critical-peak pricing (reduce energy use based on price signaling), interruptible-demand programs (requests to customers to reduce energy use) to direct-load-control programs (energy provider can reduce customer energy use). Entities within SERC-SE have the ability to control various amounts of load when needed for reliability purposes. Additional on-peak Energy Efficiency and DSM figures for SERC-SE are shown below (Table 114).

Table 114: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**92**	**107**	**15**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	371	897	526
Contractually Interruptible (Curtailable)	1,241	1,306	65
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	92	114	22
Total Dispatchable, Controllable Demand Response	**1,704**	**2,317**	**613**
Total Demand-Side Management	**1,796**	**2,424**	**628**

One example of a Demand Response program is the H2O Plus program, which uses the storage capacity of electric water heaters. This program allows entities to install load control devices that can be activated during peak demand periods, which promote the following benefits:

- Reduce the need to build or purchase capacity
- Respond to volatile wholesale energy markets
- Improve the efficiency (load factor) as well as the use of generation, transmission, and distribution systems
- Provide low-cost energy to member cooperatives
- Increase off-peak kWh sales

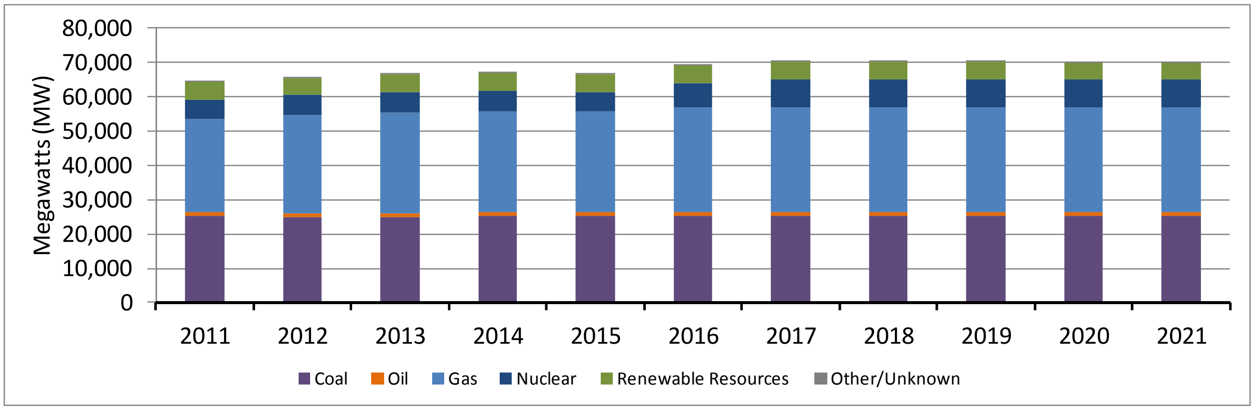
To address measurement and validation of energy-efficiency and DSM programs, entities may use third parties to conduct impact/process evaluations for commercial programs, or use Demand Response statistical models to identify the difference between the actual consumption and the projected consumption absent the curtailment event. Response may also be tracked and verified by the readings of meters, as well as testing residential and commercial summer load-control programs for verification of demand reduction through generation dispatch personnel. Evaluations may be conducted annually with a comprehensive report due at the end of a program cycle. Reports are expected to determine annual energy savings and portfolio cost-effectiveness.

To assess variability, some utilities within SERC-SE develop forecasts using econometric assessment based on approximately 40-year weather data (normal, extreme, and mild), economics, and demographics. Other entities in SERC-SE use the assessment of historical peaks, Reserve Margins, and demand models to foresee variance (optimistic and pessimistic scenarios). The economic downturn is captured within this process mainly through the reduction of load. Mild and extreme weather projections are also captured through the collection of extreme historical weather data factored into demand models.

Generation

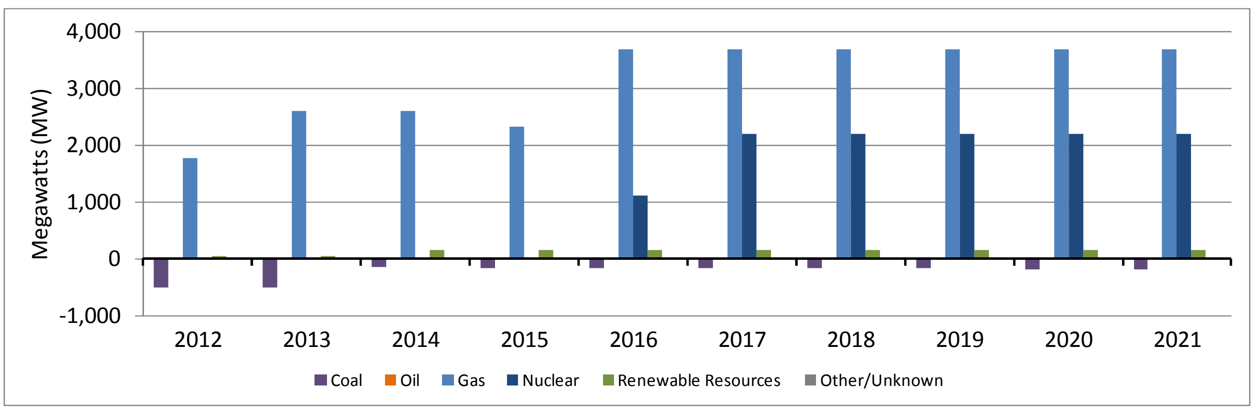
Utilities in SERC-SE expect to have the following capacity mix to help meet demand during between 2011 and 2021 (Figure 116).

Figure 116: On-Peak Capacity Mix by Fuel Type



Projections indicate large increases in natural gas and nuclear capacity for the SERC-SE Assessment Area (Figure 117).

Figure 117: Annual Net Capacity Change by Fuel Type



Variable capacity is limited within this reporting area and is not commonly included in calculations. However for some entities, *Future-Planned* biomass generation is included in their Integrated Resource Plan at less than the nameplate capacity for converted boilers and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events. Variable resources are evaluated by analyzing their historical or projected output profiles. The result is a determination of the comparative capacity value to that of a typical combustion turbine on the system. Additional information on renewable resources, including expected, derated and nameplate capacity figures for SERC-SE, are included below (Table 115).

Table 115: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	-	-	-
	Derated	-	-	-
	Wind - Total Nameplate Capacity	**-**	**-**	**-**
Solar	Expected	2	2	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**2**	**2**	**-**
Hydro	Expected	3,350	3,350	-
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**3,350**	**3,350**	**-**
Biomass	Expected	-	146	146
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**-**	**146**	**146**

Entities go through various generation expansion study processes to determine the quantity and optimal mix of resource technologies to add to the system in the future. Utilities have reported that generation reliability analyses are conducted typically for the peak period four years ahead. With the same or greater lead-time, some companies engage processes for self-building or soliciting from the market any needed capacity resources. Load forecasts are reviewed yearly and resource mix analyses are performed to determine the amounts and types of capacity resources required to meet the companies' obligations to serve. By the time the reliability analysis is conducted, those capacity resources have been committed by the companies and have high probability of regulatory approval. Power purchase agreements are also contracted from the market by that time. The resulting inputs to the reliability analyses are known or have very high confidence. Other entities review interconnection service queues to identify potential future resources to be interconnected to their transmission systems. If there are no confirmed transmission service requests or native load reservations identifying these facilities as the source, then these facilities are categorized as *Conceptual*.

While most entities within SERC-SE do not apply a confidence factor to the *Conceptual* resources, some entities have reported that recent history suggests that a 20.0 percent confidence factor may be reasonable to apply to these types of resources.

Capacity Transactions

The following imports and exports were reported for this reporting period. All imports/exports are considered to be backed by Firm contracts (no transactions are based on partial path reservations) for both generation and transmission. Expected Firm imports for the summer range from 732 MW in 2011 to 823 MW in 2021. Firm Exports drop from 2,208 MW in 2011 to 1,497 MW in 2021 (Table 116).

Table 116: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer 2011 (MW)	Summer 2021 (MW)	Winter 2011 (MW)	Winter 2021 (MW)
Imports	Firm	732	823	834	825
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**732**	**823**	**834**	**825**
Exports	Firm	2,208	1,497	2,472	1,497
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**2,208**	**1,497**	**2,472**	**1,497**
	Net Transactions	**(1,476)**	**(674)**	**(1,638)**	**(672)**

Transmission

The majority of the projects reported are load-serving in nature, with the goal of maintaining reliable service throughout the planning horizon. Plans for 500 kV expansions are primarily limited to long range needs for potential base-load plants or major load centers. Currently, there are no concerns with meeting in-service dates for transmission improvements. The economic environment has resulted in reduced load forecasts, which in turn tend to delay the need for some improvements. No reliability impacts are foreseen due to target in-service dates of transmission upgrades during the assessment period.

The utilities in SERC-SE have not identified any unusual transmission constraints that could significantly impact reliability. Additionally, there were no significant technologies that were added in the past year to improve Bulk Electric System reliability. Entities will continue to investigate the use of these new technologies to determine if they are viable to deploy on the system.

Operational Issues

Currently, there is no known existing or potential systemic outages that may impact reliability during this assessment period. Utilities continue to evaluate reliability impacts of potential environmental regulations, and solutions have been developed to address potential unit retirements. If the regulations require unavailability of significant amounts of existing generation across the Region, then the ability to procure and construct replacement generation within a given timeframe could present a reliability concern.

If peak demands are higher than forecast, entities use existing reserves and purchase additional capacity from the market, if needed, to meet system requirements. Utilities also follow various emergency procedures consistent with EOP-002[302] that allow the suspension of non-Firm sales, dispatch generation to emergency ratings, implementation of DSM programs and contacting the Reliability Coordinator for emergency capacity/energy (and various other steps). The last step in the process is to shed Firm load.

[302] NERC EOP-002 Reliability Standard: http://www.nerc.com/files/EOP-002-2_1.pdf.

Balancing Authority operators are routinely trained and conduct simulations regarding capacity shortfalls and the implementation of mitigation procedures.

As mentioned in earlier sections, operating limits related to air and/or water quality are derived from both Federal and state regulations. These restrictions are continually managed in the daily operation of the system while maintaining reliability. As a result, no existing conditions are expected to impact the reliability on the Bulk Electric System.

There are not a significant amount of distributed resources installed on the system in the SERC-SE area, and therefore there are no anticipated operational changes, concerns, or special operating procedures related to distributed resource integration. Demand Response programs currently in place do not negatively impact reliability. All programs are well coordinated with transmission and generation operations.

The utilities in SERC-SE have procedures in place to identify and review misoperations caused by protection systems. When a misoperation occurs on the transmission system, corrective action is implemented to prevent recurrence. If needed, other locations are also reviewed for problems of a similar nature. Misoperations caused by protection systems are reviewed on an annual basis for possible trends.

Emerging and Standing Reliability Issues

Risk Assessment

The utilities in SERC-SE area have identified the pending environmental regulations as an emerging issue. Current rulings are expected to require utilities to comply with the regulations beginning in early 2015. The environmental regulations may require environmental controls on all coal and oil fired electric generating units. Approximately 43.0 percent of the *Existing-Certain* capacity (more than 25,000 MW) within the SERC-SE area operates on coal or oil. These regulations may also impact 6.4 percent of *Future-Planned* capacity (430 MW).

Utilities within the SERC-SE area are assessing the potential impacts of these regulations. For some utilities, it may be uneconomical to install environmental controls on older, smaller coal or oil fired generating units, and therefore, these units could potentially be unavailable beginning in 2015. This unavailable capacity will need to be replaced in order to maintain Reserve Margins, and changing resources may create a need for additional transmission system improvements. In addition, units which are economical to control may still be unavailable given the expected three year compliance timeframe.

Environmental regulations may have a significant impact on the way the utilities within the SERC-SE area perform assessments. Resource adequacy, transmission adequacy, resource development, and operations may be impacted. Transmission adequacy concerns have a high degree of uncertainty and the extent of the transmission issues will not be known until final environment regulations are released and generation decisions have been made. Resource development issues are multifaceted since the compliance timeframe is not long enough to identify, permit, engineer, and construct new generation.

Operations will be impacted given a significant portion of the generating fleet within the SERC-SE could be changed.

Operational areas of concern under the proposed environment regulations include:

- Assessing generating resources that are considered blackstart and are used in system restoration.
- Units sharing common control equipment could increase an area's largest single contingency and therefore require operational changes to meet reliability standards.
- Installed environmental controls will likely reduce a unit's operational flexibility and therefore impact how some operating reserves are carried.

Since this is an emerging issue which will not become effective until early 2015, no reliability impacts have been experienced, and no associated improvements to the Bulk Electric System have been made.

Other Assessment Area-Specific Issues

To minimize impacts on the system, utilities within the reporting area annually perform regional assessments of the transmission system. Reliability concerns are addressed through the development of projects from 13 months throughout a 10-year period. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and Firm transmission commitments for the time period studied and are updated on a monthly basis. Transmission expansion plans include projects that exceed the requirements of current standards. The inclusion of these projects, along with preventative maintenance, will ensure that the reliability concerns are met during the assessment period.

Assessment Area Description

SERC-SE is a summer-peaking reporting area covering portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida) with a population of approximately 35.1million.[303] Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 119,800 square miles. There are four Balancing Authorities in SERC-SE: PowerSouth Energy Cooperative, South Mississippi Electric Power Association, Southeastern Power Administration, and Southern Company Services, Inc.

[303] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population.

SERC-W

Introduction

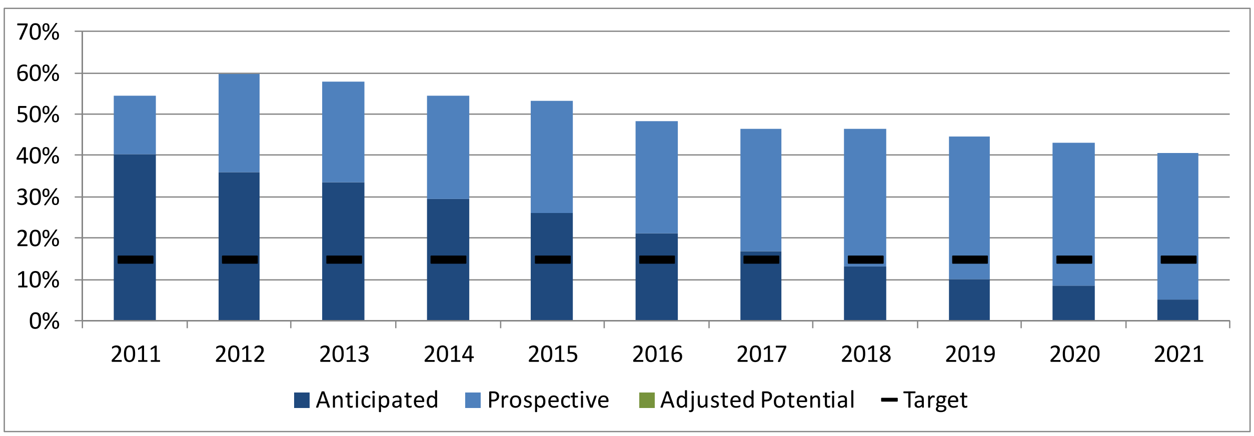
SERC-W (including Southwest Power Pool RC entities registered in SERC) is a summer-peaking area covering portions of four southeastern states (Arkansas, Louisiana, Mississippi, and Texas). The 10 registered Balancing Authorities in this area are identified as:

- Entergy
- City of Benton
- City of Conway
- City of North Little Rock
- City of Osceola
- City of Ruston
- City of West Memphis
- Louisiana Generating, LLC.
- Plum Point Energy Associates, LLC.
- Union Power Partners, L.P.

Reliability Assessment

The projected Reserve Margins for utilities within SERC-W are reported between the years 2011 to 2021 and range from 40.2 percent to 5.4 percent over the 11-year period. Reserve Margins are well above the 15.0 percent NERC Reference Margin Level for the majority of the time period, falling below 15.0 percent in 2018. Capacity resources are expected to be adequate to meet demand for the period (Figure 118)

Figure 118: Annual On-Peak Planning Reserve Margins



There are no subregional, Regional, or state Reserve Margin requirements for this reporting area. However, some individual entity criterions have been established based on the Balancing Authority's most severe single contingency, load forecast and reserve requirement using historical allocations, and/or LOLE studies (1 day in 10-years).

Various utility resource planning departments in the area conduct studies annually (either in-house or through contractors) to assess resource adequacy. Modeling of resources and delivery aspects of the power system are used in all phases of the studies. The overall goal of the studies is to ensure resources are available at the time of system peak. One example of an entity's method would be Entergy's use of their Entergy Reliability Analysis with Interruptible Loads (ERAILS) model. This model is a proprietary computer simulation model developed by the Entergy Generation Planning Group, and is used to perform the resource requirements analyses. The ERAILS model uses Monte Carlo statistical techniques to estimate each day's "actual" peak load based on the forecast load and the load forecast variance, the total resources available to serve that load based on available resources, forced outages, the characteristics of each resource, and the probability of being able to meet the load, and also factors in off-system sales and operating reserves. The fundamental objective of the process is to identify the amount of incremental resources necessary to serve Firm load at a reliability level of no more than 1 day in 10-years LOLE and to serve interruptible retail and limited-Firm wholesale loads with an average of 10 or fewer days of interruption during the summer.

Resource adequacy studies for SERC-W take into account potential resource deactivations and anticipated unit outages, limited and long-term purchase contracts. Results help develop 1- and 10-year resource plans that meet target Reserve Margins. The calculations for near_ and long-term margins are not treated differently. Although some reporting area utilities participate in the Southwest Power Pool (SPP) Reserve Sharing Group, the reporting area is not dependent on outside resources to meet its demand requirements. Additionally resource planners in SERC-W do not consider distributed generation or behind the meter generation to assess reliability and, therefore, these resources are not considered in the determination of Reserve Margins.

Fuel supplies are anticipated to be adequate. Coal stockpiles are maintained at 45 days or more. Natural gas contracts are Firm, with some plants having fuel oil back-up. Extreme weather conditions should not affect deliverability of natural gas. Typically, supplies are only limited when there are hurricanes in the Gulf of Mexico. There is access to local gas storage to offset typical gas curtailments. Many utilities within SERC-W maintain portfolios of Firm-fuel resources to ensure adequate fuel supplies to generating facilities during projected peak demand. Those Firm-fuel resources include: nuclear and coal-fired generation that are relatively unaffected by weather events, fuel oil inventories located at the dual fuel generating plants, approximately 10 Bcf of natural gas in storage at a natural-gas storage facility owned by a company within SERC-W, short-term purchases of Firm natural gas generally supplied from other gas storage facilities, and Firm-gas transportation contracts. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of potentially problematic issues on system reliability.

Close relationships (with contracts) are maintained with coal mines, gas pipelines, gas producers, and railroads that serve the area's coal power plants. These relationships ensure adequate fuel supplies are on-hand to meet load requirements. Upon the occurrence of fuel interruption or forced outage within some entity facilities, it is common that exporting contracts out of the facility will be curtailed in coordination with the affected Balancing Authorities until operations can return to normal. Currently, no entities anticipate any unit retirements that could impact reliability during the assessment period.

Energy-Only, transmission-limited variable resources and RPSs are not considered in resource adequacy assessments. Rather, only Firm capacity and Firm transmission are considered. Resources are either owned or secured by executed power purchase contracts. The majority of the utilities within the reporting area have no Demand Response programs; however, those utilities that do have these programs report that they are treated as a load modifier in resource adequacy assessments. The effects of Demand Response are incorporated into the load forecast which is treated stochastically. Transmission planners continue to study variable generation integration (like wind), and its impact on reliable transmission operations. Section 4 goes into detail on how planners account for this capacity in their models, as the generation goes through various interconnection approval processes. The resource may be assigned a confidence factor and given a 'place holder' in the model. To help provide accuracy to the approval process, system operations and power marketing departments use wind forecasting services to manage the variable output of the wind farms.

Various companies throughout the reporting area perform individual studies to assess transient dynamics, voltage and small-signal stability issues for summer peak conditions in the near-term planning horizons as required by NERC Reliability Standards. While there are no common reporting-area-wide criteria to address transient dynamics, voltage or small-signal stability issues, some utilities have noted that they adhere to voltage schedules, and voltage stability margins (usually 5.0 percent from the voltage collapse point methodology used in the PV curves). Recent 2012 summer peak internal studies indicate that with more capacity and reactive power support, flow limits on the Mt. Olive-Hartburg 500kV line needed to be increased. Based on the study results, the flow limits have been increased on the Mt. Olive to Hartburg 500 kV line and updated in all planning and operational models.

The 2011 and 2018 studies conducted by the SERC Dynamics Study Group (DSG) revealed that transmission improvements and additional reactive support or FACTS devices are needed at the Ninemile 230 kV Station and surrounding areas to help maintain voltage stability. Dynamic and static reactive power-limited areas on the system will be mitigated by proposals to install SVCs, capacitors, change transformer tap settings and add new transmission facilities. In addition, some utilities employ SVC devices to provide reactive power support and voltage stability. UVLS programs are also used to maintain voltage stability and protect against Bulk Electric System cascading events. An existing 250 MW UVLS scheme is used in the western area of Texas. No additional UVLS schemes are currently planned for the reporting area.

The bulk transmission projects planned for this period will be incrementally phased in to maintain the integrity of the system according to NERC Reliability Standards. No SPSs or RASs[304] have been planned in lieu of the transmission projects.

Resource and transmission planning activities consider contingency events to help entities prepare for catastrophic events. Close relationships with neighboring utilities and regular emergency operating drills are important practices of utilities. Entities within this reporting area are routinely exposed to

[304] RAS (Remedial Action Scheme) is another name for a Special Protection System. http://www.nerc.com/files/Glossary_12Feb08.pdf.

hurricanes, and detailed emergency response plans have been developed for dealing with the consequences of hurricane damage to area electrical systems. One way that catastrophic events are mitigated is that gas-fired power plants do not rely on a single pipeline for transportation of natural gas. Likewise, most entities do not heavily rely on imports outside the reporting areas due to the loss of a major import that could negatively affect reliability.

Utilities plan to continue to monitor the development of new technologies in order to improve and maintain Bulk Electric System reliability. Some utilities in the area are currently deploying Phasor Measuring Units (PMUs) to measure voltage and power flows across the system in a synchronized, real-time manner that will quickly and accurately describe the state and health of the transmission system, and could also be used to improve modeling results. Some utilities are currently focusing on the use of smart grid technology on home area networks, home automation, smart meters, distribution voltage control and feeder reconfiguration, but currently these are considered to have only a very indirect affect on transmission reliability. Utilities in the area continue to study the potential integration of electric vehicle (EV) chargers and customer-owned generation sources which could both challenge and enhance the reliability of electric service to customers. EV chargers result in additional load on the existing system and could possibly introduce harmonic concerns. Solar panels and wind turbines will augment generation sources, but connections must continue to be coordinated to ensure safety and reliability for customers.

There are no known environmental or regulatory restrictions currently in effect that could impact reliability. Project slowdowns, deferrals, or cancellations are not expected during the time period. On the contrary, some entities report that some of their projects are currently under budget and ahead of schedule.

Demand

The 2011 summer aggregate Total Internal Demand forecast for the utilities in SERC-W amounts to 25,101 MW. Projections indicate a 1.26 percent annual growth to 28,809 MW by 2021 (Table 117).

Table 117: On-Peak Demand

Demand	2011 (MW)	2021 (MW)	Total Growth (MW)	Average Annual Growth (%)	Assessment Period Change (%)
Total Internal	25,101	28,809	3,708	1.26%	14.8%
Net Internal	24,228	27,840	3,612	1.27%	14.9%

The LTRA projections are based on average historical summer peak weather and are the sum of non-coincident forecast data reported by utilities in the area. This year's forecast CAGR for 2011 to 2021 is 1.26 percent. Due to the restructuring of entity reporting footprints for this assessment, a comparison of demand forecasts is not available. Entities report that poor economic conditions experienced recently are assumed to continue through 2011 with a gradual return to normal conditions by 2015. No changes were made to assumptions for normal weather conditions from last year's forecast. Typical weather conditions are used to forecast the load shapes for residential, commercial, and governmental classes. The industrial load shapes are not weather-responsive. Typical weather is defined by calculating an average daily temperature from 10-years of historic weather data and determining a month that contains the lowest differential from this long-term assessment monthly average. Other factors include assumptions of new econometrically-based forecasts of commercial/industrial load, future economic/demographic conditions and historical data. Many cooperatives assess the likelihood of new distribution loads, and a probability adjustment is incorporated into their load forecasts.

Energy-efficiency programs are implemented to distribution cooperatives and the residential sector. A variety of programs ranging from home energy audits, compact fluorescent lights (CFLs), and Energy Star-rated washing machines and dishwashers, to Energy Star-rated heat pumps and air conditioners, weatherization and high-efficiency water heaters have been added to company portfolios over the years. Utilities within SERC-W plan to offer these types of programs as long as they are determined to be cost-effective. Annual M&V programs measure energy savings and costs for each of these energy-efficiency programs. Information from these M&V programs is used to fine tune Energy Efficiency programs and to determine their cost-effectiveness. The current forecast includes Energy Efficiency programs that have received regulatory approval, and as these and new programs advance, they will be incorporated into retail sales and load forecasts.

DSM programs among the utilities in the reporting area include; interruptible load programs for larger customers, direct-control load management programs for agricultural customers, and a range of Conservation/load management programs for all customer segments. There are no significant changes in the amount and availability of load management and interruptible demand since last year. M&V for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Conformity is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule. Additionally, because significant amounts of these resources are not expected during the time period, they are not used for meeting renewal portfolio standards.

Demand-Side Management and Energy Efficiency figures for SERC-W are shown below (Table 118).

Table 118: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**92**	**107**	**15**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	371	897	526
Contractually Interruptible (Curtailable)	1,241	1,306	65
Critical Peak-Pricing (CPP) with Control	-	-	-
Load as a Capacity Resource	92	114	22
Total Dispatchable, Controllable Demand Response	**1,704**	**2,317**	**613**
Total Demand-Side Management	**1,796**	**2,424**	**628**

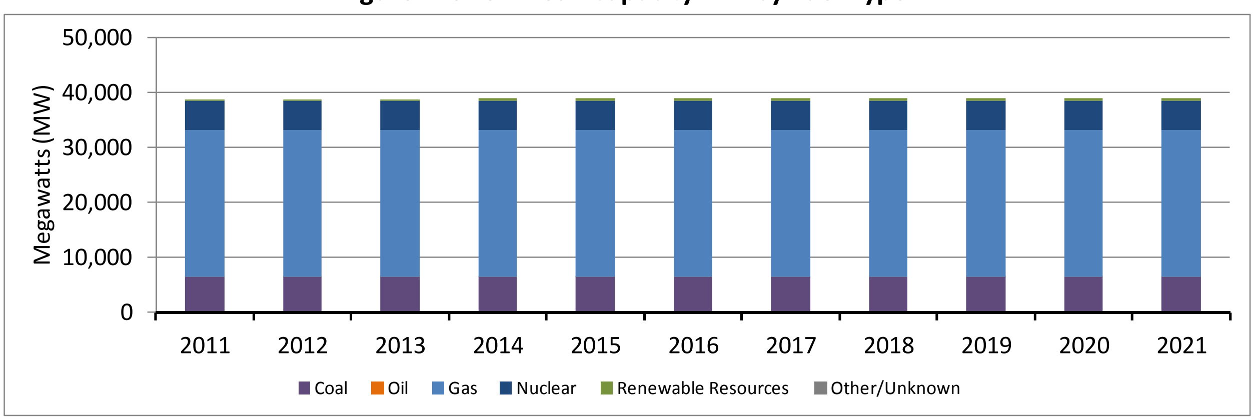
Load scenarios for outage planning purposes are developed regularly to address variability issues in demand. These load scenarios include load forecasts based on high and low scenarios for energy sales and scenarios for alternative capacity factors. The forecasts are based on normal weather, economic, and demographic conditions. Scenarios are also further modified from these forecasts to produce updated forecasts for both optimistic and pessimistic conditions. Most SERC-W entities update forecasts frequently (approximately every two years) with annual updates completed in the interim years. The economic downturn has reduced expectations of economic activity compared to previous forecasts reflected in the relatively unchanged 2011 summer forecast. This has resulted in an overall reduction of demand and energy forecasts. The current load forecast reflects lower sales through 2014, with the largest decreases in the industrial class due to reduced operations and delayed expansions.

Some entities within SERC-W address extreme weather conditions through the production of load scenarios. Other entities have a thorough planning process that examines summer peak conditions during extreme Bulk Electric System events. In the long-term planning timeframe, local loads are adjusted to reflect a 100-degree area temperature, so studies capture the effects of local extreme temperatures. For the operational planning timeframe, in addition to next-day planning, entities within SERC-W regularly study import limitations for various load pockets on the system. These analyses cover summer peak conditions, including extreme summer conditions, as necessary. Occasionally special analyses are preformed to examine conditions associated with weather events such as hurricanes, heat waves, cold fronts or ice storms.

Generation

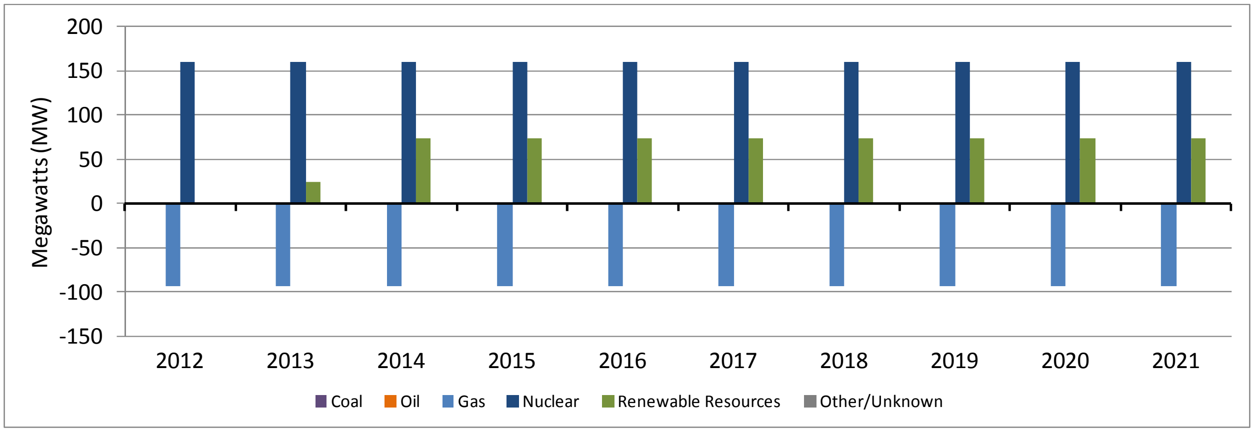
Capacity in the categories of *Existing-Certain*, -Other and -Inoperable, *Future-Planned*, and -Other), and *Conceptual* are expected to help meet demand throughout the assessment period (Figure 119)

Figure 119: On-Peak Capacity Mix by Fuel Type



SERC-W projects large additions in nuclear generation as soon as 2012. Renewable resources are also expected to come on-line during the assessment period, especially in 2013 and 2014 (Figure 120).

Figure 120: Annual Net Capacity Change by Fuel Type



Resources are evaluated based on capability to meet required reliability requirements and economics. For intermittent resources like wind, some entities base values on a time-period method using monthly capacity value measures.

The process first examines the highest 10 percent of load hours for the respective month, and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base-load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value. However, most entities in the area only counted capacity if it was considered Firm. Renewable resource figures for SERC-W are including with expected, derated and nameplate capacity values below (Table 119).

Table 119: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	-	-	-
	Derated	-	-	-
	Wind - Total Nameplate Capacity	**-**	**-**	**-**
Solar	Expected	-	-	-
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**-**	**-**	**-**
Hydro	Expected	266	290	24
	Derated	-	-	-
	Hydro - Total Nameplate Capacity	**266**	**290**	**24**
Biomass	Expected	-	50	50
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**-**	**50**	**50**

Resources identified for the purpose of reliability studies and Reserve Margin calculations include Existing owned and contracted resources as well as *Conceptual* self-build projects and Existing resources operating in forward capacity markets. Plants that can be dispatched with reliable, flexible fuel supply are considered for capacity resources. These include fossil fuel plants and hydro but do not include variable resources. Some entities have a policy not to rely on energy markets for capacity and maintain Reserve Margins mostly from internal resources. However, other entities also factor in energy-supplier review forecast information and historical reserve allocation as a participant in the SPP Reserve Sharing Group. These forecasts help area utilities to make decisions regarding the amount of capacity needed for the upcoming year.

Confidence factors are not commonly used by entities in the reporting area. Capacity is only counted if it is considered Firm. For example, wind energy is not considered for capacity due to it not being regularly available during peak demand periods. Conversely, hydro capacity is considered contractually Firm and is counted towards capacity. Other entities determined the confidence factor by using the following guidelines; if the resource is considered "place holder" generation for use in modeling, the confidence factor assigned is 25.0 percent. If the resource has been announced, on a resource planning basis, through a corporate announcement, is in the early stages of the approval process or is in a generator interconnection queue for study, the confidence factor assigned is 75.0 percent. The confidence factors assigned to *Conceptual* capacity are subjective qualitative assignments and are subject to change.

Conceptual resources for planning capacity are considered by some entities as resources that are permitted and constructed given the known market for capital, resources, and labor. These *Conceptual* resources are viable, realistic options that can be made available using prudent business practices to meet a capacity requirement. For example, simple cycle gas turbine peaking capacity can realistically be ready to serve as capacity in two years from the decision to proceed. Nuclear capacity would not be considered to be ready to serve as capacity for a much longer period of time. Other entities simply categorize all planned renewable and new build resources as *Conceptual*.

Capacity Transactions

Utilities within the reporting area expect the following imports and exports listed below (Table 120). Expected Firm imports amount to a total of 1,349 MW in 2011 with an additional 150 MW of Expected imports. Currently, no imports are projected for 2021. Projected Firm exports range from 2,158 in 2011 to 2,055 MW in 2021.

Table 120: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	1,349	-	1,370	-
	Expected	150	-	150	-
	Provisional	-	-	-	-
	Total	**1,499**	**-**	**1,520**	**-**
Exports	Firm	2,158	2,055	2,048	2,507
	Expected	150	-	150	-
	Provisional	-	-	-	-
	Total	**2,308**	**2,055**	**2,198**	**2,507**
	Net Transactions	**(809)**	**(2,055)**	**(678)**	**(2,507)**

These imports and exports have been accounted for in the Reserve Margin calculations for the SERC-W Assessment Area. All contracts for these imports/exports are backed by Firm transmission and are tied to specific generators. No imports/exports have been reported to be based on partial path reservations.

Transmission

As with any long-term construction plan involving transmission expansion, there is the usual concern with meeting in-service dates. Project delays could impact local areas resulting in increased local load at risk. However, delays would not be expected to degrade the reliability of the Bulk Electric System.

No transmission constraints are expected to significantly impact Bulk Electric System reliability for the period. Companies within the reporting area regularly participate in NTSG seasonal reliability studies. The NTSG 2011 Summer Reliability Study preliminary results indicate that imports into Entergy's system exceed 1,800 MW for all paths studied. Previous years' studies have indicated lower import levels due to the McAdams 500/230 kV autotransformer. This flowgate, which is located near a 500 kV tie within SERC-W, can be constrained due to excess generation on the interface along with transactions across the interface. However, recent and additional upgrades on schedule for completion by June 2011 have resulted in these higher import levels. Additionally, a two-phase joint project to address loading issues in the Acadiana load pocket is also currently in the construction phase with targeted in-service dates in 2011 and 2012. The majority of Phase 1 of the project was put into service in May 2011, and the final portion of Phase 1 is currently planned to be placed in service around July 2011. Since several EEAs have been issued in the past for the Acadiana area, the SPP Independent Coordinator of Transmission – Entergy (SPP-ICTE) will continue to monitor this area closely, and will implement mitigation plans as necessary as part of its Reliability Coordinator function.

Currently, there are no immediate plans for new technologies within this long-term assessment planning horizon. Utilities plan to continue to monitor the development of new technologies in order to improve and maintain Bulk Electric System reliability.

Operational Issues

There are no existing or potential systemic outages that may impact reliability during the next 10-years. If peak demands are higher than expected, entities rely on Reserve Margins from individual company owned/operated power plants, and interconnections to SPP, Midwest ISO, and neighboring utilities from which wholesale energy can be accessed. If adequate resources cannot be procured from the short-term wholesale market, entities would rely on curtailing load, first to non-Firm customers and then to Firm customers.

Additionally, there are no known environmental/regulatory restrictions or negative impacts due to high-levels of Demand Response, integration of variable resources or distributed resource issues in effect that could impact reliability. If the Mississippi river falls below 100-year drought conditions, there could be derates at the New Madrid power plant (also depending on the water temperatures). By employing barge pumps, the plant could mitigate the problem.

Utilities within SERC-W have procedures in place to identify and review misoperations associated transmission protection systems. In the event of a misoperation on the transmission system, investigations, including root cause analysis, are performed to determine corrective actions, which are then implemented. Correction action plans may cause an entity to evaluate other facilities for similar causes of misoperation.

Emerging and Standing Reliability Issues

Risk Assessment

Utilities in the SERC-W reporting area have identified an emerging issue regarding potential changes in environmental regulations. Expectations are that the regulations may result in significant modifications associated with water intake requirements at existing generating plants. These modifications associated with closed loop systems could require significant capital investments in older generating facilities and could result in potential early retirements of resources in the area. Depending on the timing of the regulations, a greater dependency on acquiring capacity resources from areas external to the SERC-W reporting area may be required until replacement capacity is constructed or secured internally to the SERC-W reporting area.

The final impact to the resource adequacy, transmission adequacy, resource development, and operations will not be known until the changing regulations are better defined and timelines have been set. The locations of existing resources impacted by the potential environmental regulation changes within the SERC-W area are expected to be throughout the area and not necessarily within a limited or specific geographical area.

Other Assessment Area-Specific Issues

To minimize reliability concerns for the period, entities within SERC-W are studying reliability with a critical and conservative approach. Any issues resulting from the studies are addressed within the appropriate timeframe. Curtailment Processes and Emergency Response Plans are routinely updated. As necessary, transmission-wide and local area procedures, re-dispatch, and operating guidelines will be implemented to maintain reliability.

Assessment Area Description

SERC-W (including SPP RC entities registered in SERC) is a summer-peaking reporting area covering portions of four southeastern states with a population of approximately 34.1million[305]. Owners, operators, and users of the Bulk Electric System in these states cover an area of approximately 133,500 square miles. There are 10 Balancing Authorities in SERC-W: Entergy, City of Benton, City of Conway, City of North Little Rock, AR, City of Osceola, City of Ruston, LA, City of West Memphis, Louisiana Generating, LLC, Plum Point Energy Associates, LLC, and Union Power Partners, L.P.

[305] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population.

SPP

Introduction

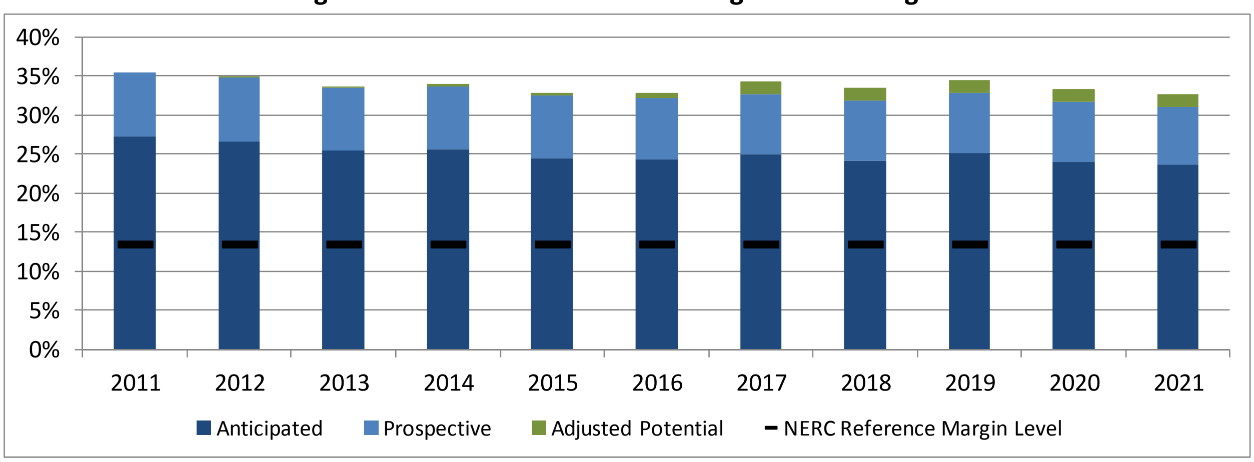
The SPP Region is a summer-peaking Assessment Area that operates and oversees the electric grid in the southwestern quadrant of the Eastern Interconnection. In addition to serving as a NERC Regional Entity (RE), SPP is a Federal Energy Regulatory Commission (FERC) approved RTO. The SPP RTO footprint includes all or part of nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.[306] The Nebraska members belong to the Midwest Reliability Organization Regional Entity, but this year's assessment is being performed on the SPP RTO footprint, which includes the Nebraska members.

On behalf of the SPP RE, this assessment provides information on the Region's forecasted resource adequacy throughout the long-term assessment period. This report is created with data and information submitted by SPP Reporting Entities, which is validated and cross-checked to verify consistency. After this process is completed, SPP RE staff aggregate the information into one data set for the entire SPP RTO Region. SPP RE staff use a peer review process to validate data and develop reliability assessments.

Reliability Assessment

For this long-term assessment period, the forecasted Reserve Margin based on Anticipated Capacity Resources for 2011 is 27.2 percent; it decreases to 23.6 percent in 2021. SPP Criteria requires SPP RTO members to meet a 12 percent capacity margin, which translates to a 13.6 percent Reserve Margin (Figure 121). These margins are also expected to cover a 90/10 weather scenario.

Figure 121: Annual On-Peak Planning Reserve Margins



[306] To read more about the differences between the SPP RE and SPP RTO footprints: http://www.spp.org/publications/SPP_Footprints.pdf.

In October 2010, the SPP RTO completed the Loss-of-Load Expectation (LOLE) and Expected Unserved Energy Study for the 2016 time period.[307] The study evaluated the need to adjust SPP's 12 percent capacity margin or 13.6 percent Reserve Margin, and estimated the Reserve Margin required to achieve an LOLE of no more than 1 day in 10-years. Based on the LOLE study performed by SPP RTO staff in 2010 for the summer of 2016, the capacity or Reserve Margin requirement for the SPP RTO remained unchanged. The 12 percent capacity margin and 13.6 percent Reserve Margin requirements are also cross-checked annually in the EIA-411 reporting, as well as through supply adequacy audits the SPP RTO conducts every five years of Regional members. The last supply adequacy audit was conducted in 2007.

The SPP RTO expects 60,500 MW of internal and external resources to meet the Region's targeted Reserve Margin during the assessment period. As part of the inter-Regional transmission transfer capability study, the SPP RTO participates in the Eastern Interconnection Reliability Assessment Group seasonal study group (comprised of MRO, RFC, SERC West, and SPP), which produces operating condition transfer limitation forecasts for an upcoming summer and winter assessment, as well as a long-term summer assessment for a NERC-determined future year. Simultaneous transfers are performed as part of this study. Study results that were finalized May 9, 2011 did not indicate any reliability issues for the SPP area.

SPP RTO members, along with neighboring Registered Entities, such as Entergy from the SERC Region, have formed a Reserve Sharing Group (RSG). Members of this group receive contingency reserve assistance from other SPP RSG members. SPP's Operating Reliability Working Group sets the minimum daily contingency reserve requirement for the SPP RSG. The SPP RSG maintains a Minimum Daily Contingency Reserve, over and above its Regulating Reserves, equal to the generating capacity of the largest unit scheduled to be on-line plus one-half of the capacity of the next largest generating unit scheduled to be on-line within the SPP RSG each day.

The SPP RTO does not treat short-term (1-5 year) and long-term (6-10) Reserve Margin requirements differently. SPP has a single minimum capacity margin requirement for the entire 10-year assessment period of 12 percent or a 13.6 percent Reserve Margin. As mentioned above, the SPP RTO's Reserve Margin is above this threshold in 2011 and maintains above the requirement throughout the 10-year assessment.

SPP defines Firm deliverability as electric power intended to be continuously available to buyers even under adverse conditions. For example: power for which the seller assumes the obligation to provide capacity (including SPP-defined capacity margin) and energy. Such power must meet the same standards of reliability and availability as that delivered to native load customers. Power purchased can be considered Firm only if Firm transmission service is in place to deliver the power to the load serving member. SPP does not include financial Firm contracts in this category. Existing long-term Firm delivery is ensured by provisions in the SPP Transmission Expansion Plan, while new long-term Firm delivery is ensured by Aggregate Transmission Service Studies. These procedures are included in the SPP Open

[307] SPP.org>Engineering>2010 Loss-of-Load Expectation (LOLE) Report

Access Transmission Tariff (OATT).[308] Finally, behind the meter generation is shown in this report as *Existing-Certain* capacity.

The SPP RTO reviews potential fuel supply limitations by consulting with its generation-owning and generation-controlling members via email. There are no known infrastructure issues which could impact fuel deliverability, as the SPP Region is blanketed by major pipelines and railroads that provide an adequate fuel supply. SPP RTO Criteria require coal and natural gas-fired power plants, which make up approximately 48 percent and 44 percent of total generation respectively, respectively to maintain sufficient quantities of standby fuel on site in case of deliverability issues.[309] Because hydro capacity is a small fraction (approximately one percent) of capacity for the Region, run-of-river hydro issues brought about by extreme weather are not expected to be critical.

Due to the diverse generation portfolio in the SPP RTO, there is no concern that fuel supplies will be affected by summer weather extremes during peak conditions. If a fuel shortage is anticipated, SPP RTO members are to communicate to the RTO operations staff in advance so that appropriate measures can be taken. In the case of insufficient capacity or reserves due to unavailable generation, the SPP RTO would declare either an Energy Emergency Alert (EEA) or Other Extreme Contingency (OEC) and would report any related information on the Reliability Coordinator Information System (RCIS).

SPP does not expect any immediate impact on the Regional reliability due to current economic conditions. The SPP RTO footprint continues to see a modest amount of load growth over the assessment period and capacity remains adequate. Transmission projects have not been negatively impacted due to economic conditions in the Region.

The SPP RTO is expected to meet Reserve Margin requirements without reliance on energy-only and transmission limited resources. These resources are not used in calculating the net capacity margin.

States in the SPP RTO footprint that have a Renewable Portfolio Standard or Goal are Oklahoma, Kansas, Missouri, New Mexico, and Texas. The renewable energy targets were included in the WITF Study and Priority Projects analysis.[310] Variable resources such as wind and solar are considered as *Existing-Certain* resources per the requirements of SPP Criteria 12.1.5.3. The Integrated Transmission Planning (ITP)[311] process evaluates high wind scenarios along with other environmental and regulatory factors such as a carbon tax. Demand response programs in the SPP RTO footprint are voluntary and because the amount is insignificant (approximately 1 percent) it is not included in the planning process.

There are no known unit retirements during the assessment timeframe which will impact reliability in the SPP RTO footprint. However, proposed Federal environmental regulations which have compliance

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[308] SPP.org>Regulatory>Interactive Tariff page (attachments O and Z1).

[309] SPP Criteria 2.4.2: http://www.spp.org/publications/Criteria%20and%20Appendices%20April%2025,%202011.pdf.

[310] Oklahoma's renewable goal was established in May 2010, after the completion of the WITF Study.

[311] SPP Criteria: http://www.spp.org/publications/Criteria%20and%20Appendices%20April%2025,%202011.pdf.

dates beginning in 2012 through 2020 could cause the retirement of several coal and gas units in the SPP RTO footprint. The SPP RTO's recently completed study[312] on the impact of these regulations shows expected generation retirement scenarios ranging from 1,000 MWs to 3,000 MWs. The loss of this amount of base-load generation could jeopardize the reliability of the Region if replacement resources cannot be acquired or built in time or if simultaneous prolonged outages are required to retrofit a large number of units. The scenarios indicated the SPP RTO's Reserve Margins based on *Existing-Certain*, and Net Firm Transactions could be reduced to between 18.2 percent and 14.6 percent respectively in 2015 and 12.7 percent and 9.3 percent respectively in 2021. Reserve Margins based on Anticipated Capacity Resources could be reduced to between 22.7 percent and 19.1 percent respectively in 2015 and 21.9 percent and 18.5 percent respectively in 2021. See the discussion in the "Emerging and Standing Reliability Issues" section below for additional information.

The SPP RTO has an undervoltage load shedding program in western Arkansas within the AEP-West footprint. This program targets about 186 MW of load shed during the peak summer conditions to protect the bulk power system against undervoltage events.

The SPP RTO has seven Special Protection Systems (SPS) that are approved to be in place from 18 months to 5 years based on the reliability need. All SPS requests are reviewed and approved by SPP's System Protection and Control Working Group. The SPP RTO does not have any SPS or Remedial Actions Schemes (RAS) installed in place of planned bulk power transmission facilities.

In 2009, the SPP Board of Directors approved a new Integrated Transmission Planning (ITP) process that will determine the transmission needed to maintain electric reliability and provide near-term and long-term economic benefits to the SPP RTO Region.[313] Successful implementation of the ITP will result in a list of transmission expansion projects and completion dates that facilitate the creation of a reliable, robust, flexible, and cost-effective transmission network that improves access to the Region's diverse resources, including its vast potential for renewable energy. Significant wind energy development is taking place in parts of Oklahoma, Kansas, Nebraska, and Texas.

The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments. The 20-Year Assessment evaluates high voltage transmission (above 345 kV) needs over a 20-year period to meet load growth and other future scenarios and potential developments.[314] The first iteration of the 20-Year Assessment,[315] conducted and concluded in 2010, included an examination of high voltage transmission needs while taking into account state renewable energy targets. Transmission needs were studied both with and without a potential 20 percent Federal Renewable Energy Standard (RES) and a

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[312] Review of the Potential Reliability Impacts of Proposed EPA Regulations Impacting Generation in the SPP Footprint, July 19, 2011, available on SPP.org (July 26, 2011, Board of Directors/Members Committee Meeting Background Materials, Pages 185-195): http://www.spp.org/publications/BODAGD&BKGD072611-E.pdf.

[313] SPP.org>Engineering> Transmission Planning>Integrated Transmission Planning.

[314] SPP uses a stakeholder process to determine what futures are studied during each ITP cycle.

[315] SPP.org>Engineering>Transmission Planning>Integrated Transmission Planning>2010 ITP20 Report (01/26/11).

potential carbon tax. The renewable energy generation in a 20-year future without a Federal RES was 10.6 GW, and the renewable energy generation in a future with a Federal RES was 16.5 GW.

The 10-year assessment is a value-based planning approach that analyzes the transmission system from 2011 through 2021. Economic and reliability analyses are used to identify 100 kV and above solutions for issues identified on the 69 kV and above system, as well as issues identified by the 20-Year Assessment appropriate for this long-term assessment period. The first iteration of this long-term assessment is ongoing throughout 2011. This study, like the 20-Year Assessment, examines transmission needs while considering state renewable energy targets and a potential 20 percent Federal RES. The renewable energy generation in a 10-year future without a Federal RES is 10.0 GW, and the renewable energy generation in a 10-year future with a Federal RES is 14.0 GW. The study is also examining the effects of proposed EPA coal regulations on transmission needs.

The ITP Near-Term Assessment evaluates transmission system reliability in the near-term planning horizon. The Assessment will identify potential problems using NERC Reliability Standards, SPP Criteria, and local planning criteria. Mitigation plans are developed to meet Regional reliability needs and identify necessary reliability upgrades for all voltage levels for approval and construction. The first iteration of the Near-Term Assessment is being conducted in 2011.

The ITP process, through its 20-Year, 10-Year, and Near-Term Assessments, seeks to target a reasonable balance between long-term transmission investment and congestion costs to customers. While the SPP RTO does not have a planning process in place at this time for catastrophic events, it does assess and study all events as required by NERC Standards TPL-003 and TPL-004.[316]

The objective of the 2010 Transient Stability Compliance Assessment was to report findings that support compliance with NERC TPL- 001, TPL- 002, TPL-003 and TPL-004 Reliability Standards.[317]

The goals of the Transient Stability Assessment were to:

1. Perform a stability screening using 3-phase fault for the SPP system operated above 100 kV
2. Perform a detailed stability assessment for those events identified as unstable in the screening analysis
3. Perform a detailed stability analysis for member submitted events (Category B, C and D)
4. Identify a mitigation plan for those events that indicate potential stability violations

The initial unstable NERC Category B and Category C Events were mitigated by applying either the proper clearing time or system generation re-dispatch to maintain system stability. The unstable NERC Category D Events were made stable by tripping the unit made unstable by the event offline and applying more realistic clearing times. This mitigation technique for NERC Category D was chosen due to the severity of the events that were being modeled. The clearing times used for the system scan were

[316] TPL-003-0 - http://www.nerc.com/files/TPL-003-0a.pdf; TPL-003-1a http://www.nerc.com/files/TPL-003-1a.pdf; TPL-004-0http://www.nerc.com/files/TPL-004-0.pdf; TPL-004-1 http://www.nerc.com/files/TPL-003-1a.pdf

[317] http://www.nerc.com/page.php?cid=2|20

generic based on the kV of the line segment. If an unstable event was found, the SPP RTO contacted the member and replaced the generic clearing time with actual clearing times, which were faster. The closing times were chosen based on the average clearing time for a breaker at a certain kV level.

The SPP RTO is in the early stages of documenting and implementing a reactive planning process and expects to have this process completed by the end of 2012. The SPP RTO does not have criteria for voltage stability margins in the reporting area, but is in the process of determining what the voltage stability margins should be for each member area in the Region. The SPP RTO is looking into several new smart grid systems/tools, but no decisions have been made on their deployment timeframe.

Based on these studies, the SPP RTO does not anticipate any near-term or long-term reliability issues that have not been addressed by mitigation plans or with local operating guides. There are no known project slow-downs, deferrals, cancellations, or other issues at this time that will impact the SPP RTO footprint's reliability.

The SPP RTO conducted a Power-Voltage (P-V) analysis study for nine potential load pockets within the SPP RTO footprint based on a 2014 summer peak load condition. The study found that the Midland, Texas area within the Southwestern Public Service Company footprint may face voltage issues during the 2014 summer peak if planned projects are not built on time. However, the Midland load pocket may be significantly reduced by a load transfer to ERCOT, invalidating the need for any projects. The SPP RTO Project Tracking process will continue to track these projects and monitor any additional load transfer developments with ERCOT. SPP RTO staff will coordinate any potential reactive reserve issues and associated mitigation plans during their annual reliability assessment effort.

Demand

According to the most recent forecasted data, the projected compound annual rate of growth for peak Total Internal Demand in the SPP RTO Region between 2011 and 2021 is 0.96 percent (Table 121), similar to the 2010 forecast.

Table 121: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	53,084	58,948	5,864	0.96%	11.0%
Net Internal	51,783	57,526	5,743	0.96%	11.1%

SPP RTO has 21 reporting members who annually provide a long-term forecast of peak demand and net energy requirements. These forecasts are used to develop an overall non-coincident SPP RTO forecast. The forecasts are developed in accordance with the following principles:

- Each member selects its own demand forecasting methodology and establishes its own forecast.
- Each member forecasts demand based on expected weather conditions.
- Each member submits to the SPP RTO the methods used, factors considered, and assumptions made, along with the annual forecast.

- When producing the forecast, the SPP RTO considers economic, technological, sociological, demographic, and any other significant factors

The SPP RTO's peak demand is the non-coincident peak for the entire Region. The Resource evaluations made by the SPP RTO and the members are based on summer peaking conditions.

Energy Efficiency programs in the SPP RTO area are approximately 153 MW in 2011, increasing to 282 MW in 2021 (Table 122). The capacity and Reserve Margin projections include the effects of demand-side response programs, such as direct-control load management and interruptible demand. The SPP RTO does not have an organized demand response program at this time, but it is expected that by 2021, interruptible demand will increase from 1,133 MW to 1,141 MW. These demand response values are based on projections using historical data and trends; they do not reflect increased demand response as directed by FERC in the evolution of SPP's market design.

Table 122: On-Peak Energy Efficiency Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**153**	**282**	**129**
Non-Controllable Demand-Side Management	**3**	**376**	**373**
Direct Control Load Management	162	275	113
Contractually Interruptible (Curtailable)	1,133	1,141	9
Critical Peak-Pricing (CPP) with Control	5	5	-
Load as a Capacity Resource	-	-	-
Total Dispatchable, Controllable Demand Response	**1,300**	**1,422**	**121**
Total Demand-Side Management	**1,457**	**2,080**	**623**

In March 2010, SPP RTO member Oklahoma Gas and Electric Company (OG&E) installed approximately 42,000 smart meters on customer homes in Norman, Oklahoma, along with the information delivery infrastructure to carry the information between OG&E and its customers. An estimated 3,000 Norman customers are expected to continue participating in the study during the summer of 2011 using the in-home devices and/or Internet portals as a means to get electricity pricing and use information. Program results will not be available until after the two-year study period concludes. Currently, no significant increases in distributed or behind the meter generation are projected during the long-term assessment period.

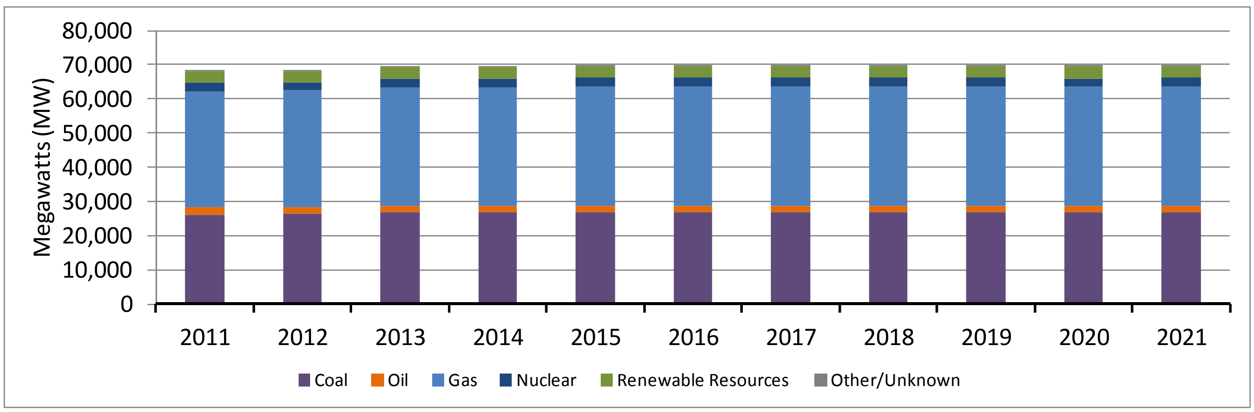
Although actual demand is very dependent on weather conditions and typically includes interruptible loads, forecasted Net Internal Demands are based on 10-year average summer weather, or 50/50 weather. Some SPP RTO members determine peak forecast based on a 50 percent confidence level, as approved by their respective state commission. This means the actual weather on the peak summer day is expected to have a 50 percent likelihood of being hotter or a 50 percent likelihood of being cooler than the weather assumed in deriving the load forecast. The SPP RTO does not develop load forecasts based on a 90/10 weather scenario, but has a 13.6 percent Reserve Margin requirement to address this uncertainty.

To quantify peak demand uncertainty and variability due to extreme weather, economic conditions, and other variables, the SPP RTO formed a Bandwidth Working Group. This group produced the Demand and Energy Bandwidth Report,[318] which supports the current projected growth rates and allows for up to a 1.2 percent variation from the base demand forecast in current and future projections through the year 2012. The report also determined the 13.6 percent Reserve Margin is adequate to cover any extreme load for the SPP RTO footprint. The SPP RTO anticipates this trend will continue for the remaining assessment period. SPP is currently seeking a load forecasting tool that will have the capability to forecast both demand and energy.

Generation

For the 2011-2021 assessment period, the SPP RTO projects to have 65,090 MW *Existing-Certain* Capacity; 4,417 MW *Existing-Other* Capacity; 364 MW Existing, Inoperable; 5,437 MW Future Capacity; and 9,786 MW *Conceptual* resources in service or forecasted to be in service during the assessment period (Figure 122). The *Existing-Certain* Capacity amount from renewable plants is 260 MW (wind), 2,650 MW (hydro), and 11 MW (biomass).

Figure 122: On-Peak Capacity Mix by Fuel Type

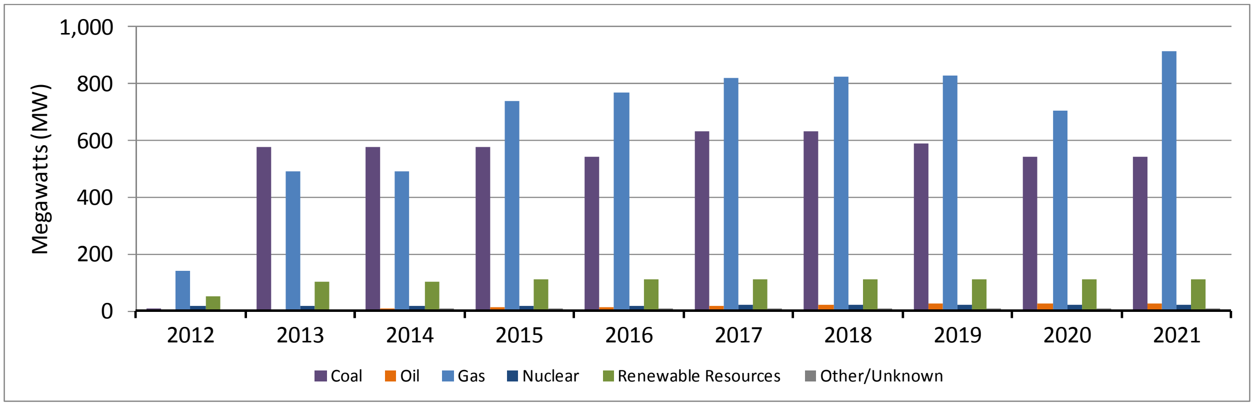


For the reporting of Future and *Conceptual* capacity resources, the SPP RTO uses the Generation Interconnection and Transmission Service Request study processes as defined in the SPP OATT. According to the OATT, when the interconnection request is submitted, the interconnection customer must request either energy resource interconnection service or Network Resource interconnection service. Any interconnection customer requesting Network Resource interconnection service may also request that it be concurrently studied for energy resource interconnection service, up to the point when an interconnection facility study agreement is executed. Interconnection customers may then elect to proceed with Network Resource interconnection service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed. The SPP RTO *Future-Planned*, and *Conceptual* resources include active requests that are currently in the generation interconnection queue to be studied, in addition to the member-reported *Future-Planned*, and

318 *Demand and Energy Bandwidth Forecast 2003-2012* (September 2003): http://www.spp.org/publications/BWG_Report_2003.pdf.

Conceptual resources. Only those resource categorized as either *Future-Planned* or *Future-Other* are included in the figure below (Figure 123).

Figure 123: Annual Net Capacity Change by Fuel Type



Planned capacity for 2021 from renewable resources amount to 339 MW. These reported renewable resource additions in the SPP RTO do not reflect merchant wind farm development in process, incremental needs which may result from RES mandates/goals within the SPP RTO Region, or public announcements for additional renewable expansion by SPP RTO members. The SPP RTO has requests to connect approximately 28,164 MW of generation (mostly wind) to the SPP RTO grid via the Generation Interconnection queue. All on-peak and expected derates for the renewable resources in the SPP Area are included below (Table 123).

Table 123: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	260	339	79
	Derated	3,135	3,847	712
	Wind - Total Nameplate Capacity	**3,395**	**4,186**	**791**
Solar	Expected	66	74	8
	Derated	-	-	-
	Solar - Total Nameplate Capacity	**66**	**74**	**8**
Hydro	Expected	2,650	2,664	14
	Derated	112	112	-
	Hydro - Total Nameplate Capacity	**2,762**	**2,776**	**14**
Biomass	Expected	11	20	9
	Derated	-	-	-
	Biomass - Total Nameplate Capacity	**11**	**20**	**9**

Conceptual capacity resources forecasted for 2011-2021 are projected to be 28,164 MW. Variable generation of 20,049 MW nameplate capacity composes the majority of the *Conceptual* resources. SPP Criteria Section 12.0 discusses capacity values and how they are calculated for the Region based on a wind farm's historical performance. The SPP RTO applies a 10 percent confidence level to all *Conceptual* capacity unless otherwise reported by SPP RTO members.

Capacity Transactions

A small portion of SPP RTO capacity or Reserve Margin depends on purchases external to the SPP RTO, as shown below (Table 124). Total Imports are projected to fall from 5,155 MW in 2011 to 4,483 MW in 2021. Exports are also projected to fall from 4,044 MW in 2011 to 3,559 MW in 2021. The sales and Firm contracts are backed by Firm generation and transmission, and are based on partial path reservations.

Table 124: Seasonal On-Peak Capacity Transactions

	Transaction Type	Summer		Winter	
		2011 (MW)	2021 (MW)	2011 (MW)	2021 (MW)
Imports	Firm	5,021	4,452	4,474	7,628
	Expected	135	31	25	25
	Provisional	-	-	25	25
	Total	**5,155**	**4,483**	**4,524**	**7,678**
Exports	Firm	4,044	3,559	3,887	3,436
	Expected	-	-	-	-
	Provisional	-	-	-	-
	Total	**4,044**	**3,559**	**3,887**	**3,436**
	Net Transactions	**1,111**	**924**	**637**	**4,242**

Transmission

The SPP RTO identified several transmission projects as critical projects needed to maintain or enhance reliability within the Region. These critical projects were determined by a Region-wide study looking at N-1 contingencies based on TPL-002. These high voltage lines solved overload and voltage issues within the SPP RTO Region. If for some reason the in-service dates are not met, mitigation plans are identified for each project. Mitigation plans could include area specific operational measures or a temporary reconfiguration of the transmission system in the area, among other measures.

There are no known concerns about meeting target in-service dates for reliability projects that have been approved by the SPP RTO Board of Directors. Assuming these projects come on line as scheduled, there are no known transmission constraints that could impact the reliability of the SPP RTO transmission grid. The SPP RTO relies heavily on its Project Tracking process to track projects and ensure they meet their issued timelines.[319] If a project's timeline is extended, the SPP RTO will conduct a study to address any reliability issues associated with the extension. There is no significant substation equipment identified at this time.

Operational Issues

The SPP RTO operations group does not expect any systemic outages that will impact Regional reliability. SPP RTO participates in the SPP Reserve Sharing Group which provides assistance during Energy Emergencies. Demand response and curtailable contract sales may also be implemented during appropriate emergency levels.

[319] The Engineering section of SPP.org has a page on project tracking: http://www.spp.org/section.asp?pageID=114.

In the long-term, there are no expected restrictions that will impact reliability. The generation fleet within the SPP RTO remains diverse in terms of location, fuel type, and capability. Depending on the long-term penetration of wind generation in the footprint, the SPP RTO could experience some operational issues. The impact of wind generation in the SPP RTO footprint is discussed in the "Emerging and Standing Reliability Issues" section.

Integrating variable resources provides some challenges for SPP in managing grid congestion in an equitable manner. SPP continues to pursue incentives and requirements for variable resources to be controllable and responsive in a manner similar to other non-variable resources. This is in the system's best interest in terms of reliability and equity.

Distributed generation consisting of non-controllable variable energy resources could lead to increased challenges in load forecasting because most of the distributed generation resources are located behind the meter. In the long-term, the volume of distributed generation is not forecast to have an impact in the SPP RTO. According to SPP RTO operational staff, there are no known operational changes/concerns resulting from distributed resource integration, and SPP does not anticipate any reliability concerns as a result of demand response resources.

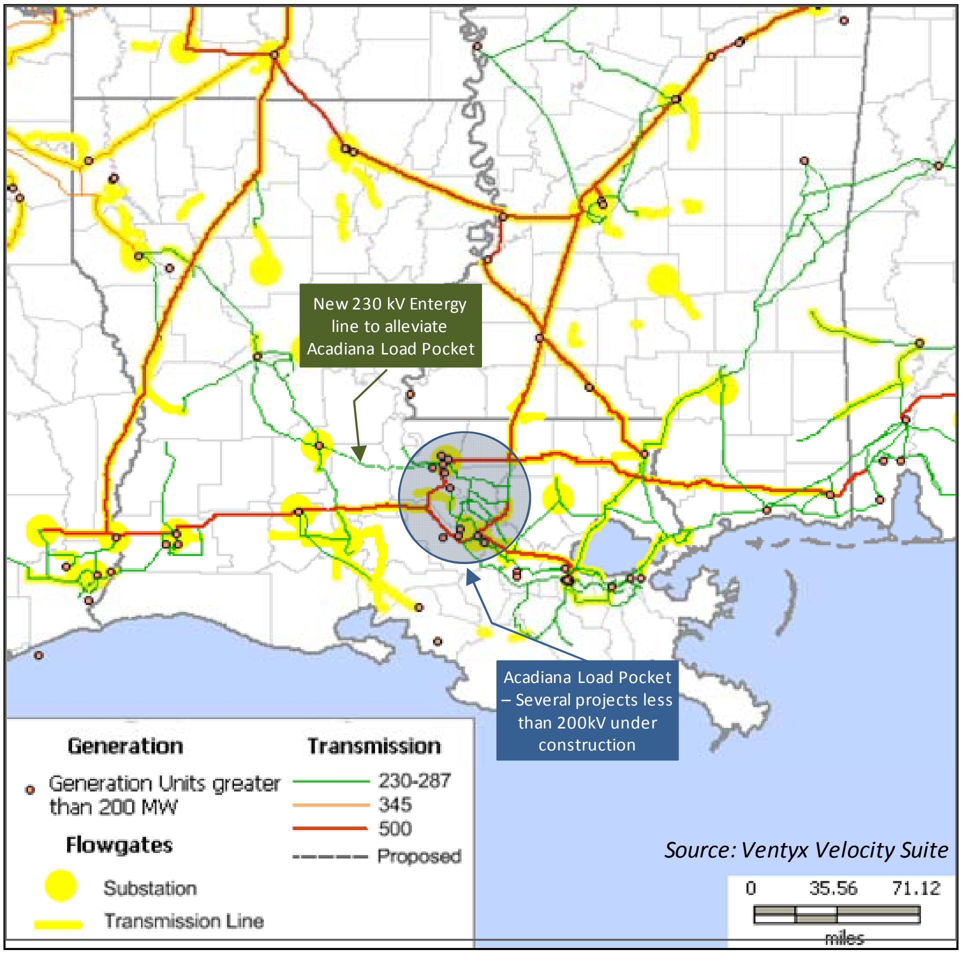
The SPP RTO reviews, on a quarterly basis, several years of SPP RTO Protection System misoperations data looking for trends that could be used to help reduce the number of misoperations in the future.

Emerging and Standing Reliability Issues

Acadiana Load Pocket

The Acadiana Load Pocket (ALP) located in southern Louisiana, with a 2010 summer peak demand of 1,723 MWs, spans both the SPP RE and SERC reliability areas and continues to be constrained as transmission improvements are being constructed (Figure 124). The SPP RTO has been aware of congestion issues in this area since 2006 due to the lack of efficient generation and transmission capacity that limit the amount of import capability. The City of Lafayette, CLECO, and Entergy are in the process of constructing reliability additions and upgrades in the Region. The first phase of the project, which includes a 230 kV line from Roark to Sellers Rd., was energized on May 3, 2011. This line has already alleviated some of the most limiting elements in the ALP by as much as 10 percent. Completion of the entire project in 2012 should further alleviate some of the transmission congestion in this area.

Figure 124: Acadiana Load Pocket



The SPP Reliability Coordinator (RC) continues to aggressively address the system characteristics listed above by coordinating with all of the impacted entities. The SPP RC and ALP entities' operational Planning Engineering staffs developed operating guides, and ALP entities are sharing generation cost of legacy generation required to dispatch during system events. This coordinated effort on the part of all ALP parties has limited the load at risk. There has been an increase in the ALP load over the last few years due to catastrophic weather events on the Louisiana gulf coast that redistributed the population from larger load centers near the coast to Acadiana. ALP Transmission System events in the ALP do not pose a significant threat to the Eastern Interconnection as these events are restricted to the boundaries of the ALP.

Once the transmission projects are complete, older ALP generation may retire, and the area will shift become transmission dependent, instead of generation dependent.

Variable Energy Integration

The SPP RTO has been aware of potential variable energy integration issues since the 2003-2004 timeframe. The SPP RTO recently worked with AMEC Earth and Environmental and SPS/Xcel Energy staff to investigate the operational impacts of increased wind penetration to secure reliable operations within the SPS area. SPS serves a 52,000 square mile area in southeastern New Mexico, the Texas

Panhandle, portions of Oklahoma, and a small part of Kansas. Due to significant existing, approved, and requested wind farm development, constraints must be resolved in the near-term before major transmission capability is installed to improve internal and interface capabilities.

The recently completed AMEC study for spring 2010 conditions focused on operations and reliability, and did not investigate the economics associated with planned and potential wind development within and surrounding the SPS Balancing Authority. The study leveraged the National Renewable Energy Lab's wind data for 2004-2006 to simulate future scenarios for 2010. Without considering proactive wind curtailments as an option, the study concluded that Operating Margins[320] during low load periods within SPS would be jeopardized as wind farm development approached 1,100 to 1,200 MW– only slightly above existing wind capacity levels, without curtailments. SPS is working with the SPP RTO to finalize operating procedures for curtailment of generation resources based on transmission priority and communicate them to generation developers as a near-term solution. SPS has a posted curtailment policy for curtailment of resources if necessary.[321]

In anticipation of a surge in renewable resources on the western part of its grid, the SPP RTO completed the WITF Study in January 2010.[322] This study reinforced the criticality of coordinating transmission expansion plans with wind generation construction plans. The study recommended significant bulk Extra High Voltage (EHV) transmission additions (230 kV, 345 kV and/or 765 kV) for a high wind scenario. If the needed transmission upgrades were completed, there would be no significant technical barriers or reliability impacts to integrating wind energy levels up to 20 percent of total capacity in the SPP RTO.

For the near-term, the study identified the need to develop a process for determining what generating units are used throughout the Region, explicitly addressing the uncertainty associated with wind forecast errors. Recommendations resulting from the WITF study were assigned to the Markets and Operations Policy Committee, and implementation of the recommendations has been integrated into the stakeholder process. The implementation of a centralized wind energy forecasting system was also recommended. The SPP RTO evaluated two wind forecasting systems and selected one that became operational in January 2011. The new forecasting tool relies on historic and real-time wind speed and direction, air temperature, barometric pressure, and other factors such as each turbine's manufacturer, location, availability, and metered output to generate five-minute, hourly, and day-ahead forecasts. SPP operators previously projected wind power availability by reviewing current power output and assuming the same circumstances would be true ten minutes into the future.

Additional data collection and situational awareness has been implemented to begin assessing regulation and spinning reserve needs. The WITF Study also indicated that the SPP RTO would need significant transmission additions to accommodate wind capacity of 10 percent or more of total capacity

[320] An operating margins is the amount of backup generation available to handle load as wind generation reduces.

[321] SPS Schedule Curtailment Policy Version 1: http://www.oatioasis.com/SPS/SPSdocs/XEL-PRO-_Transmission_Procedure_manual__schedules.pdf.

[322] Access the WITF Study from the Org Groups page of SPP.org, Wind Integration Task Force section: http://www.spp.org/section.asp?group=1385&pageID=27.

in the SPP RTO. For the assessment period, approximately four percent of installed wind capacity is counted towards the Reserve Margin even though a large percentage of wind generation is available in the SPP wholesale energy market for energy-only purchase.

Reliability concerns associated with the continued influx of wind generation will consist of regulating the large percentage of variable energy resources and curtailments of the variable resources during times of transmission congestion. Consolidating the Balancing Authorities in the SPP RTO's Integrated Marketplace will help facilitate wind integration in the region, but additional changes to the SPP OATT, interconnection agreements, operating procedures, and market design may be required to maintain adequate operating margins within portions of SPP as wind development continues.[323]

New HVdc Line Proposals

SPP became aware of a High Voltage Direct Current project in 2009. Tres Amigas proposes constructing a "super station" to link America's three primary electric transmission grids – the Eastern Interconnection (SPP), the Western Interconnection (WECC) and the Electric Reliability Council of Texas (ERCOT), which serves the majority of Texas.[324]

SPP became aware in mid-2010 of two additional HVDC lines that may be constructed in the southwest part of the SPP system by Clean Line Energy. The first project, the Plain & Eastern line, is a 7,000 MW capacity, 800-mile long facility that is planned to begin in western Oklahoma and end in western Tennessee.[325] The second Clean Line Energy project, the Grain Belt Express Line,[326] will deliver 3,500 MWs of renewable energy from western Kansas to communities in southeastern Missouri. The clean energy will be transported via an approximately 550 mile overhead, HVDC transmission line.

The Tres Amigas and Clean Line Energy projects are in the planning stages with projected in-service dates of 2014-2015. However, these projects are not Firm, nor are the in-service dates. SPP has just begun the technical evaluation of these projects. Should the proposed facilities be constructed and placed in service, SPP may be faced with a large number of transmission requests. SPP may not be able to approve all of the requests until additional transmission facilities are built. However, SPP's current processes should prevent any reliability impacts to the Bulk Electric System.

Potential U.S. Environmental Regulations

In July 2011, the SPP RTO completed a study on four potential U.S. regulations that could impact the reliability of the Bulk Electric System in the SPP Footprint. The four regulations include:

- The Clean Water Act – Section 316(b)
- Clean Air Act – Hazardous Air Pollutants (HAP)

[323] Consolidating Balancing Authorities was recommended in the NERC Report *Accommodating High-Levels of Variable Generation, 2009*: http://www.nerc.com/files/IVGTF_Report_041609.pdf. A follow-up report was also published titled *Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, 2011:* http://www.nerc.com/files/IVGTF2-3.pdf.

[324] tresamigasllc.com.

[325] plainsandeasterncleanline.com.

[326] grainbeltexpresscleanline.com.

- Cross State Air Pollution Rule (CSPAR)
- Coal Combustion Residuals Rule (CCR)

This study examined a likely range of generation retirement scenarios from 1,000 MWs to 3,000 MWs.[327,328] The scenarios indicate SPP RTO's Reserve Margins are projected to be reduced (Table 125).

Table 125: Reserve Margin Impact from Potential Federal Environmental Regulations

Resource Category	2015		2021	
	1,000 MW	3,000 MW	1,000 MW	3,000 MW
Existing, Certain, and Net Firm Transactions	18.2%	14.6%	12.7%	9.3%
Ancitipated Capacity Resources	22.7%	19.1%	18.6%	15.2%

Due to the amount of generation retirements and/or outages these regulations could cause in the SPP RTO footprint and the corresponding impact to reliability, the SPP RTO made two recommendations to the EPA.[329] The first recommendation seeks a gradual compliance schedule to allow the industry time to meet the proposed requirements in a reliable, safe and economic manner. The second recommendation asks that the EPA include a temporary waiver mechanism under which the affected generation owner could seek an extension to allow the generator to continue to operate while solutions such as transmission expansions or demand response programs can be put in place. SPP RTO believes that adoption of these recommendations will allow for the development of compliance plans that will lessen or avoid the negative impact to grid stability caused by mass generator outages and/or retirements.

Other Assessment Area-Specific Issues

SPP knows of no other Region-specific issues that could impact reliability besides those mentioned earlier in this report. The SPP RTO continues to perform real-time, current day, next day, and seasonal reliability assessments for the SPP RTO footprint. The results of these studies are shared with SPP RTO members and coordination occurs using these studies to prepare to operate the system reliably.

Assessment Area Description

The Southwest Power Pool, Inc. Regional Transmission Organization (SPP RTO) Region covers a geographic area of 370,000 square miles and has members in nine states: Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas. SPP's Reliability Coordinator footprint includes 29 balancing authorities and the RTO has over 48,000 miles of transmission lines. SPP typically experiences peak demand in the summer months.

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[327] It is important to note that although the study did not include reciprocating internal combustion engine (RICE) regulation impacts to small municipally-owned generators, it did include the CATR. Changes in the Cross-State Air Pollution Rule were not considered.

[328] The SPP RTO's study of the potential Federal environmental regulations was limited to an assessment of the overall system reliability impacts. As the exact rules become more evident, further studies will be necessary to assess the impact to local congestion and local resource adequacy.

[329] See Footnote 11. Letter dated July 19, 2011 from SPP President and CEO, Nick Brown to the U.S. Environmental Protection Agency, available on SPP.org (July 26, 2011, Board of Directors Members Committee Meeting Background Materials, Pages 196-198).

SPP has 64 members that serve over 15 million people. SPP's membership consists of 14 investor-owned utilities, 11 municipal systems, 12 generation and transmission cooperatives, 4 state agencies, 7 independent power producers, 10 power marketers, and 6 independent transmission companies. SPP was a founding member of the North American Electric Reliability Corporation in 1968, and was designated by the Federal Energy Regulatory Commission as an RTO in 2004 and a Regional Entity (RE) in 2007. As an RTO, SPP ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. The SPP RE oversees compliance enforcement and reliability standards development.[330]

[330] Additional information can be found on the SPP website: spp.org.

WECC

Introduction

WECC is divided into nine subregions for this long-term assessment.[331]

- Alberta, Canada (AESO)
- Basin (BASN)
- British Columbia, Canada (BC)
- California-North (CALN)
- California-South (CALS)
- Northwest (NORW)
- Rockies (ROCK), Desert Southwest (DSW)
- WECC-Mexico (MEXW)

WECC staff and the WECC Loads and Resources Subcommittee prepared an annual Power Supply Assessment (PSA) that uses load and resource forecasts submitted by the WECC's 37 Balancing Authorities (BA). The PSA establishes expected subregion planning margins under normal and adverse weather conditions. The load and resource data used for the PSA was also used for this assessment. The PSA used a Building Block methodology for determining subregion 'target' Reserve Margins. Detailed information regarding the PSA forecast data collection process and Building Block methodology is available in the PSA report.[332]

This assessment presents WECC's response to NERC's *2011 Long-Term Reliability Assessment* request for a Regional assessment, including information specific to each of the nine subregions.

Reliability Assessment

Region and Subregion Reserve Margins are based on Anticipated Resource Reserve Margins[333] and Adjusted Potential Resource Reserve Margins (Figure 125).[334]

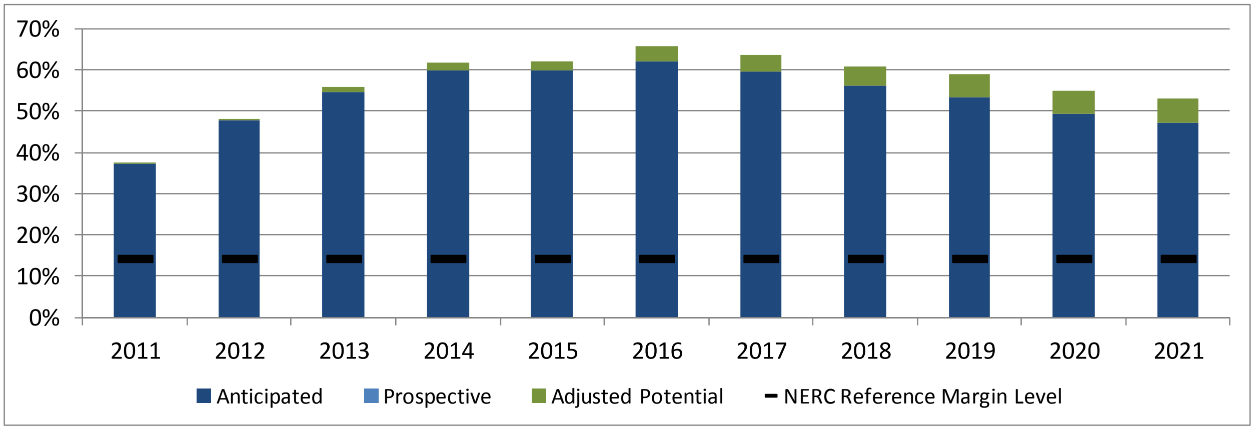
[331] Different subregions are used for seasonal assessments.

[332] WECC 2010 Power Supply Assessment: http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/2010%20Power%20Supply%20 Assessment.pdf.

[333] Based on projected transfers and the peak values of the *Existing-Certain* and *Future-Planned* resources.

[334] Based on the Anticipated Resources, plus adjusted Conceptual resources.

Figure 125: Annual On-Peak Planning Reserve Margins



By the summer of 2021, the difference between WECC's Anticipated Resources (260,940 MW, including 5,230 MW of demand response) and WECC's Total Internal Demand (177,123 MW) is forecasted to be 83,817 MW, amounting to a 47.3 percent Anticipated Reserve Margin (58,666 MW above WECC's NERC Reference Margin Level). Since reported capacity resources result in planning Reserve Margins that exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service during the planning horizon.

WECC does not have an interconnection-wide formal planning Reserve Margin standard. As previously mentioned, the WECC annual PSA[335] summer and winter target Reserve Margins were developed using a Building Block method. The Building Block method takes into account factors for weather, forced outages, operating reserves, and operating contingencies.

One of the goals of the assessment is to identify subregions within the Western Interconnection that have the potential for electricity supply deficits that could result in Reserve Margins below targets, based on reported total demand, resource, and transmission data. While the Western Interconnection has multiple back-to-back direct current transmission connections with the Eastern Interconnection, the margin analysis only considers resources within the Western Interconnection.

NERC's assessment process treats Demand Response programs as if they are sharable between Load-Serving Entities (LSE), BAs, and subregions. However, Demand Response programs in WECC generally have limitations on the number of times they can be activated. For example, some can only be activated during a declared local emergency. Consequently, Reserve Margins may be overstated, as they do not reflect the potential for certain Demand Response programs being unavailable to respond to external energy emergencies. Most LSEs within WECC treat Demand Response as a safety net that is available should circumstances, such as unexpected generator forced outages or extreme temperature events, result in unanticipated low operating margins.

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[335] WECC's Power Supply Assessment: http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/Forms/AllItems.aspx.

There are Reserve Sharing Groups (RSG) covering each of the WECC subregions except California and Mexico. In general, the LSEs in each RSG only count on the resources within their RSG footprint. California's Balancing Authority of Northern California and the Turlock Irrigation District are members of the Northwest Power Pool Reserve Sharing Group (NWPP RSG) and share reserves across transmission interconnections with other NWPP RSG members. However, for purposes of WECC's PSA and this assessment, these BAs were included in the California-North subregion, where they are geographically located. California's Imperial Irrigation District is a member of the Southwest Reserve Sharing Group (SRSG) and shares reserves across transmission interconnections with other SRSG members. For this assessment, it is included in the California-South subregion, where it is geographically located.

In the resource adequacy process, each BA maintains responsibility for complying with resource adequacy requirements established by the respective state or provincial area(s) in which they operate. Some BAs perform resource adequacy studies as part of their Integrated Resource Plans, which usually include 20-year projections. Other BAs perform resource adequacy studies that have a very short-term focus (one or two years). WECC's PSA has a study period of 10-years and uses the same zonal target Reserve Margins throughout the entire period.

Energy-Only and Energy-Limited resources (*e.g.,* the portion of wind resources not projected to provide generation at the time of peak), and transmission-limited resources are not counted toward meeting resource adequacy in this assessment, nor in WECC's PSA. Also, distributed and behind-the-meter generation not monitored by the BA energy management systems were not considered actual resources, and therefore excluded from Total Internal Demand and resource adequacy calculations.

WECC staff does not prepare a fuel supply interruption analysis and does not analyze effects of drought conditions. However, these types of studies are performed by the individual LSEs and BAs within the Region, and have not reported any fuel supply or drought-related issues to WECC. Also, WECC staff does not analyze effects of forced outages beyond the reserve for forced outages that is one of the four elements of the PSA Building Block methodology. Historically, WECC has not experienced significant on-peak capacity reductions due to either fuel supply interruptions or drought conditions.

Several states with load internal to WECC have issued state-mandated Renewable Portfolio Standards (RPS).[336] These are discussed in greater detail within the individual subregion sections. The RPS requirements have accelerated the use of renewable resources, a majority of which is wind generation. In some areas, where large concentrations of wind resources have been added, BAs have increased the amount of available regulating reserves to accommodate for increased variability. If this trend continues, BAs with increasing levels of wind generation will likely need to carry additional Operating Reserves. Other tools have been implemented to manage wind variability and uncertainty in order to reduce the amount of additional operating reserves. Specifically, wind forecasting systems have been implemented by some BAs, while others have developed wind curtailment and limitation procedures for use when generation exceeds available regulating resources.

[336] States with Renewable Portfolio Standards: http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm.

There are a variety of methods used to establish an expected available capacity for wind resources. Some BAs do not count wind resources toward total on-peak capacity. Others use historical information to project how much can be counted on in reliably meeting demand. Alternately, one BA has established a capacity value for wind using a Load Duration Curve method that averages the wind contribution during the highest 90 summer-load hours.

For resource adequacy assessments, WECC staff uses a production cost model to calculate coincident peak demand and available variable resources for the entire WECC Region. The model creates annual demand curves for each year of the study period using an algorithm of the annual peak, annual energy, and BA-specific historic hourly-demand curves. These curves are aggregated to produce coincident peaks for WECC and each of the nine subregions. For variable generation, wind curves were created using three-years' worth of one-hour interval wind speed data, and solar production curves were created using two years of solar insolation data. Hydro generation is dispatched economically, limited by expected annual energy output. The coincident peak demands and expected peak hour outputs for variable generation resources created during this simulation are reported in this assessment.

On May 4, 2010, California's State Water Resources Control Board (SWRCB) adopted a policy regarding once-through cooling used at electricity-producing power plants in California. *Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*[337] provides clear and consistent standards for implementing the Clean Water Act for electricity-producing power plants, which operate under National Pollutant Discharge Elimination System (NPDES) permits issued by California's nine Regional Water Boards. In developing the policy, the State Water Board staff met regularly with representatives from the agencies that oversee the electricity supply grid (including the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator) to develop realistic and phased-in implementation plans and schedules. Under the draft policy, the State Water Board will continue to work with the energy agencies to ensure that the compliance schedules assure electric supply reliability. Information regarding the policy, a proposed policy amendment and the compliance plans filed by the owners of the 19 plants (21,000 MW) is available on the SWRCB website.[338] The current fluid nature of compliance plans combined with long-term plans for California's resource additions has created problematic issues in producing a detailed reliability assessment. Despite these circumstances, WECC staff is currently not aware of planned individual unit retirements that are expected to have a significant impact on reliability.

The Voltage Support and Reactive Power Standard[339] established criteria for minimum dynamic reactive requirements. Dynamic reactive power support and voltage control are essential during system disturbances. Synchronous generators, synchronous condensers, and Static VAr Compensators (SVC) are able to provide dynamic support. Entities within WECC have installed under voltage load-shedding (UVLS) schemes, however, WECC does not have criteria regarding UVLS reporting.

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[337] http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/alamitos/docs/ags_ip2011.pdf.

[338] SWRCB Once-Through Cooling Information: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

[339] http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/Shared%20Documents/Voltage%20Stability%20Guide.pdf.

Several WECC entities have installed, and will continue to install, special protection systems (SPS) to maximize cost-effective utilization of the transmission system. Generally these systems are installed as permanent facilities.

WECC has not implemented a planning process for catastrophic events. However, some entities have prepared individual planning studies related to potential area-specific events. An example of this is the California study regarding once-through-cooling (referenced above).

WECC does not have a definition for generation deliverability, but transmission facilities are planned in accordance with NERC and WECC planning standards. These standards establish performance levels that are intended to limit adverse effects on the ability of each transmission system to serve its customers, accommodate planned inter-area power transfers, and meet transmission obligations to others. These standards do not require the construction of transmission to address intra-Regional transfer capability constraints. WECC has a process for the study and review of System Operating Limits (SOL). This process divides WECC into regional groups responsible for performing and approving seasonal studies on significant paths to determine a maximum SOL rating.

Planning Authorities and the Transmission Planners are responsible for ensuring compliance with TPL Standards within their respective area. These entities create datasets and run simulations before sending results to the WECC System Review Work Group (SRWG), which compiles and develops WECC-wide base cases used for the WECC Annual Study Program.[340] The Annual Study Program provides base cases for use by WECC members and staff to facilitate ongoing reliability and risk assessments of the Western Interconnection. The Annual Study Program rotates its focus on specific areas of WECC subregions. In addition to providing WECC members with an assessment of the WECC transmission system, the Annual Study Program report helps support compliance with requirements in the NERC Reliability Standards relating to reliability assessments, Special Protection Schemes (SPS), and other system data.

If the results of the Annual Study Program do not meet the criteria for expected performance levels, 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 are listed below.

- An islanding scheme for loss of the AC Pacific Intertie that separates the Western Interconnection into two islands and drops load in the generation-deficit southern island;
- A coordinated off-nominal frequency load shedding and restoration plan;
- Measures to maintain voltage stability;
- A comprehensive generator testing program;
- Enhancements to the processes for conducting system studies; and
- A reliability management system.

[340] Study not currently available to the public.

Seasonal operating studies are reviewed to ensure that SOLs of critical transmission paths are identified and managed through nomograms and operating procedures. Four Subregional Study Groups prepare seasonal studies for major paths on a coordinated subregional basis. Based on these ongoing activities, transmission system reliability within the Western Interconnection is expected to meet NERC and WECC standards throughout the assessment period.

Transmission operators and planners perform system-specific reliability studies to ensure performance meets or exceeds NERC and WECC standards. As mentioned earlier, the SRWG has an annual study program process that compiles and develops WECC-wide power flow and stability models (base cases). WECC staff and the SRWG perform selective transient dynamic and post-transient analysis on these base cases and compile all results in the study program report.

WECC has an additional standard that requires large generators with high initial response exciters to be equipped with active properly functioning Power System Stabilizers (PSS). The PSS standard acts to modulate the generator field voltage to dampen low frequency electrical power oscillations on the transmission system. Due to this standard and the studies required therein, WECC does not regularly perform interconnection-wide small signal stability studies.

The WECC TPL-(001-004)-WECC-1-CR-System Performance Criteria[341] provides guidance on voltage support requirements, reactive power requirements, and disturbance performance criteria. The WECC transient voltage dip criteria are contained within these criteria. Planning Authorities and Transmission Planners are responsible for ensuring that their respective areas are compliant with the pertinent WECC Criteria and TPL/PRC Standards.

Entities within WECC are aggressively pursuing new technologies to improve grid efficiency and reliability. These technologies include “smart metering programs” and synchrophasors. For example, the California ISO (CAISO) initiatives include exploring ways automation and advanced metering can foster participation from potential Demand Response resources in its market.[342]

WECC is highly reliant on coal-fired generation and is therefore vulnerable to reduced reliability due to pending environmental regulations. Currently, WECC staff has not prepared detailed studies on potential plant emission regulations, due to the unsettled nature of these issues. WECC staff is also not aware of any project slow-downs, deferrals or cancellations of either generation or transmission that are expected to adversely impact regional reliability.

[341] WECC's TPL – (001 thru 004) – WECC – 1 – CR System Performance Criteria: http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20through%20004%20-WECC-1-CR%20%20System%20Performance%20Criteria%20Effective%20 April%2018%202008.pdf.

[342] CAISO - Smart Grid Roadmap and Architecture: http://www.caiso.com/green/greensmartgrid.html.

Subregional Reliability Assessment

The planning Reserve Margins, or target margins, shown below, (Table 126) were derived using the 2011 load forecast and the same method as the 2010 PSA. The PSA uses a building block method for developing and planning Reserve Margins and has four elements:

1. Contingency reserves
2. Operating reserves
3. Reserves for additional forced outages
4. Reserves for one-year-in-ten weather events

Table 126: WECC Subregional Planning Reverence Reserve (Target) Margins

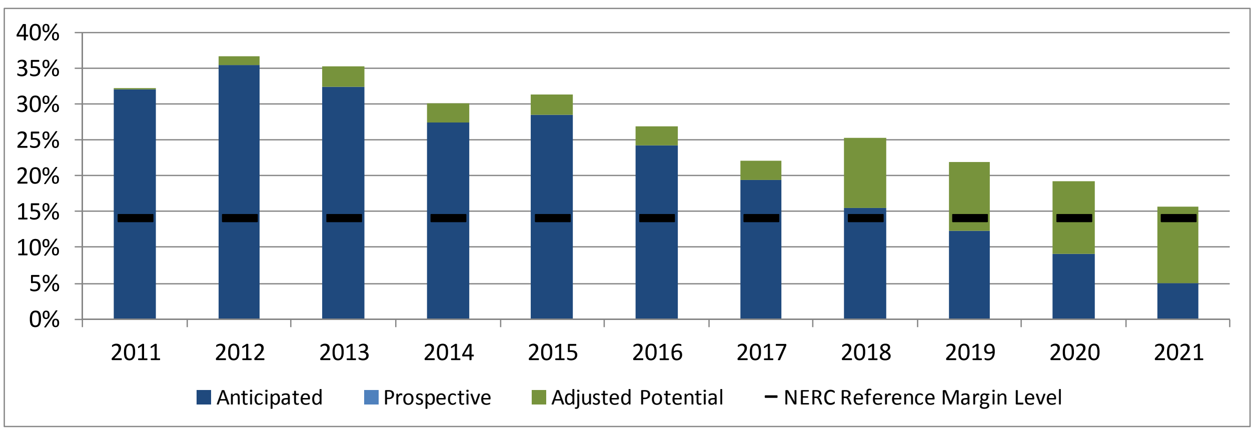
Season	WECC	AESO	BC	BASN	CALN	CALS	DSW	NORW	ROCK	MEXW
Summer	14.2%	12.3%	12.3%	12.6%	14.2%	14.9%	13.5%	17.2%	12.5%	11.9%
Winter	14.5%	14.1%	14.1%	12.5%	11.0%	12.1%	13.8%	20.3%	13.9%	10.6%

The figures in each sub regional Reliability Assessment section below show the planning Reserve Margins for the peaking season for all nine WECC subregions.

Alberta, Canada (AESO)

The 2011 target Reserve Margins for the Alberta Electric System Operator (AESO) subregion is 12.3 percent for the summer and 14.1 percent for the winter. The projected Anticipated Resource Reserve Margin for Alberta approaches the target margin as early as 2018 – highlighting the need for additional resources in the subregion (Figure 126).

Figure 126: Annual On-Peak Planning Reserve Margins – AESO



Alberta planning entities are aware of the need for resource adequacy and transmission reinforcement and believe that through the open market and proper planning, adequate resources will be available throughout the assessment period.

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

The AESO prepares a Long-Term Adequacy Metrics report[343] each quarter that includes a probabilistic assessment of encountering a supply shortfall with a two-year outlook. On a probabilistic basis, the calculation estimates how much load may go without supply over the next two-year period. Based on extensive stakeholder consultation, when this un-served energy is projected to exceed 1,600 MWh in any two-year period (equivalent to a one-hour 800 MW shortfall in each of the two years), the AESO 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 accomplished by implementing one of the following three options:

- Load Shed Service
- Self supply and back-up generation support from existing backup generation owned by commercial businesses or other entities
- Emergency portable generation.

The un-served energy projected in the most recent probabilistic assessment does not reach the 1,600 MWh threshold.

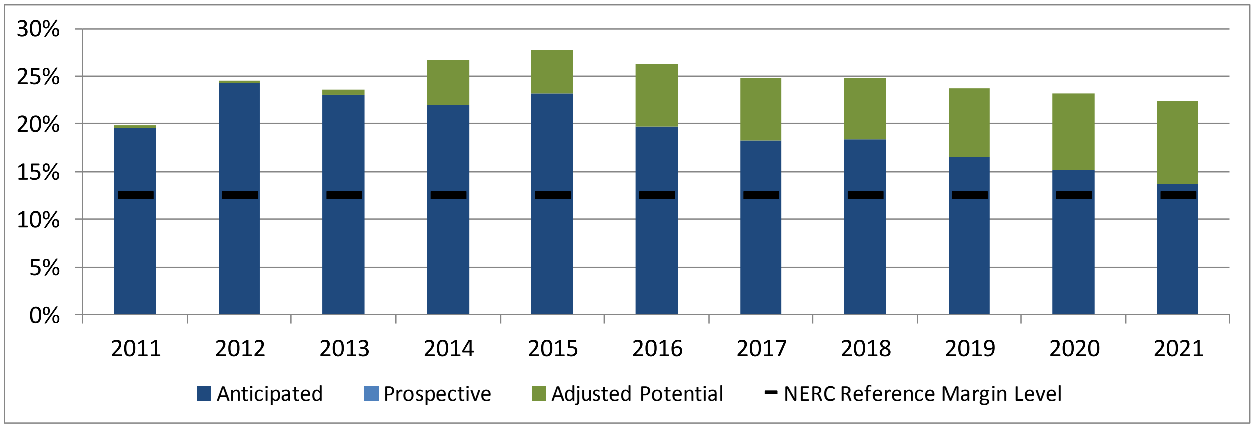
Wind generation has increased rapidly in the area. Of the existing wind resources within WECC, the AESO subregion has 940 MW, which is derated to 227 MW during the winter peak period. The AESO subregion is a net importer with forecasted imports expected to remain constant throughout the assessment period.

Basin (BASN)

The Basin subregion target Reserve Margins are 12.6 percent for the summer and 12.5 percent for the winter. The projected Anticipated Resources Reserve Margin does not go below the target margin during the assessment period (Figure 127).

[343] AESO's Long-term Adequacy Metrics: http://www.aeso.ca/downloads/2011_05_LTA.pdf.

Figure 127: Annual On-Peak Planning Reserve Margins – BASN



Of the existing wind resources within WECC, the Basin subregion has 2,221 MW, which is derated to 522 MW during the summer peak period. While wind integration may pose issues at some point, there are currently no significant integration issues that adversely impact system reliability.

The Basin subregion has not established a process for assessing resource adequacy. However, individual entities within the subregion have addressed resource adequacy as a part of either their integrated resource planning process or other similar process.

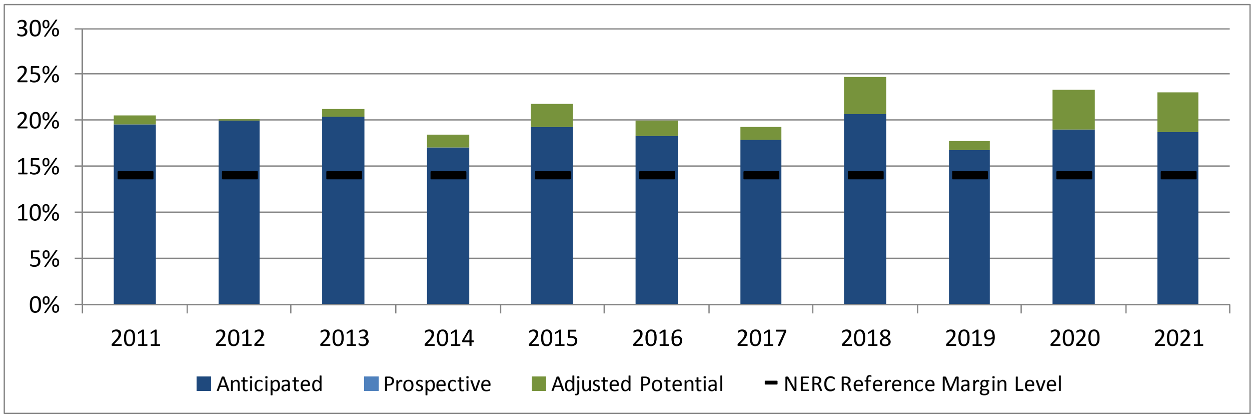
Historically, coal-fired generation has been the predominant area resource. Much of the coal-fired generation is near the fuel sources and is generally operated in a base-load mode. However, gas-fired generation has increased significantly in recent years and is expected to be the major non-renewable resource addition for the coming decade.

The Basin subregion is a net importer with forecasted imports expected to remain constant throughout the study period. The Basin subregion may be able to import additional resources if peak demand is higher than forecast.

British Columbia (BC)

The BC subregion target Reserve Margins are 12.3 percent for the summer and 14.1 percent for the winter. In the BC subregion, the projected Anticipated Resources Reserve Margin ranges between 16.7 and 20.7, remaining above the target margin during this assessment period. (Figure 128).

Figure 128: Annual On-Peak Planning Reserve Margins – BC

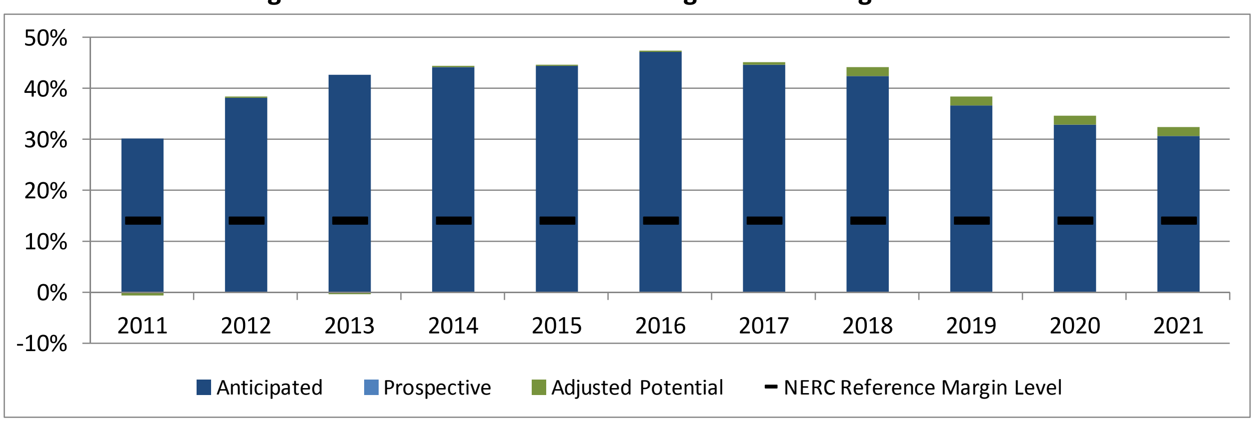


Wind generation is expected to increase in the area. Of the existing wind resources within WECC, the BC subregion has 147 MW, which is derated to 124 MW during the winter peak period.

California-North (CALN)

The California-North (CALN) subregion target Reserve Margins are 14.2 percent for the summer and 11.0 percent for the winter. The projected Anticipated Reserve Margins are not projected to fall below the target Reserve Margins during the assessment period (Figure 129).

Figure 129: Annual On-Peak Planning Reserve Margins – CALN



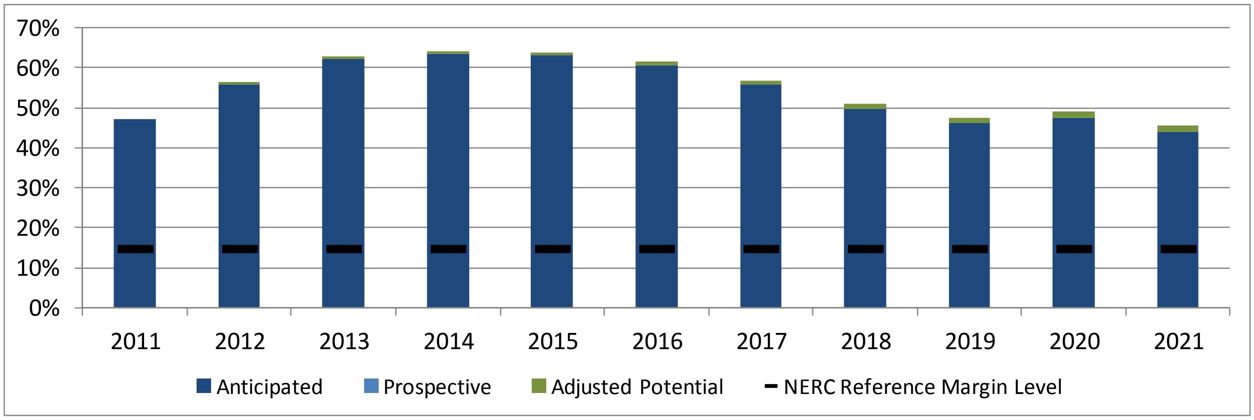
Of the existing wind resources within WECC, the California-North subregion has 1,213 MW, which is derated to 913 MW during the summer peak period.

The California-North subregion is a net importer with forecasted imports expected to remain constant throughout the study period.

California-South (CALS)

The California-South subregion target Reserve Margins are 14.9 percent for the summer and 12.1 percent for the winter. The Anticipated Resources Reserve Margins do not fall below the target Reserve Margins during the assessment period (Figure 130).

Figure 130: Annual On-Peak Planning Reserve Margins – CALS



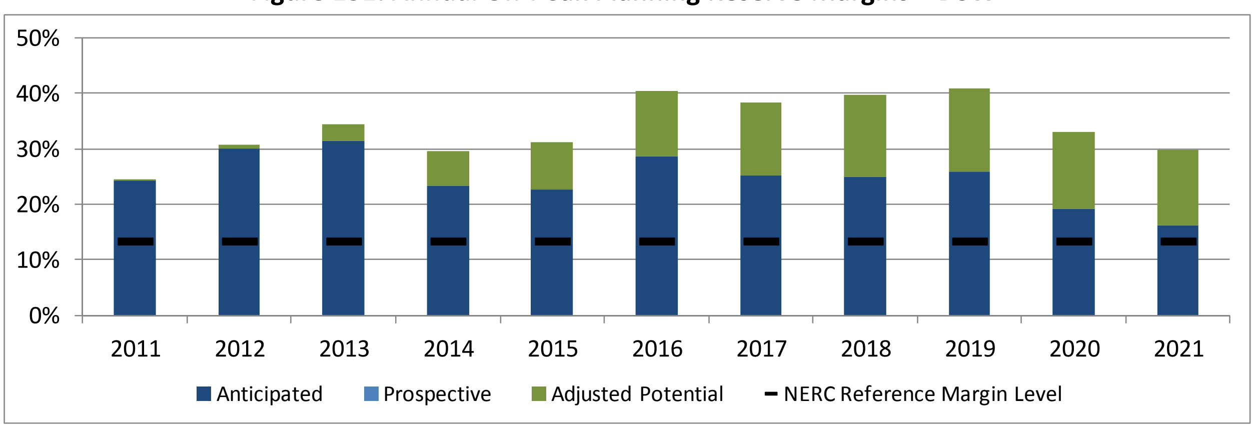
Of the existing wind resources within WECC, the California-South subregion has 1,551 MW, which is derated to 3 MW during the winter peak period.

The California-South subregion is a net importer with forecasted imports expected to remain constant throughout the assessment period.

Desert Southwest (DSW)

The Desert Southwest (DSW) subregion target Reserve Margins are 13.5 percent for the summer and 13.0 percent for the winter. The Anticipated Resources Reserve Margins are not projected to fall below the target Reserve Margins during the assessment period (Figure 131).

Figure 131: Annual On-Peak Planning Reserve Margins – DSW



Of the existing wind resources within WECC, the Desert Southwest subregion has 584 MW, which is derated to 25 MW during the summer peak period.

In Arizona, the Renewable Portfolio Standards (RPS) consists of a set of financial incentives from a large number of programs.[344] The Salt River Project (SRP) RPS involves the Sustainable Portfolio Principles established by the SRP Board in 2004, and revised in 2006. These principles direct the SRP to establish a goal to meet a target of 15 percent of its projected retail energy requirements from sustainable resources by 2025. Sustainable resources include all supply-side and demand-side measures that reduce the use of traditional fossil fuels.

Nevada has an RPS that was established by the Public Utilities Commission of Nevada (PUCN) that requires 20 percent energy by 2015. The PUCN also allows utilities to meet the standard through renewable energy generation (or credits) and energy savings from Energy Efficiency measures. At least five percent of the standard must be generated, acquired, or saved from solar energy systems.

The New Mexico Public Regulation Commission (PRC) established an RPS of 20 percent by 2020. In August 2007, the PRC issued an order[345] and rules requiring that investor-owned utilities meet the 20 percent by 2020 target through a "fully diversified renewable energy portfolio" which is defined as a minimum of 20 percent solar power, 20 percent wind power, and 10 percent either biomass or geothermal power, beginning in 2011. Additionally 1.5 percent must come from distributed renewables by 2011, rising to 3 percent in 2015.

As with other areas within WECC, the long-term projections for the adequacy of generation supply in this area will depend on how much new capacity is actually constructed. Frequently, resource acquisitions, including load-reduction options, are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, and other factors that introduce challenges in forecasting resource adequacy over an extended period of time.

The Desert Southwest subregion has not established a process for assessing resource adequacy. However, individual entities within the subregion have addressed resource adequacy as a part of either their integrated resource planning process or other similar process.

Coal, hydro, and nuclear plants are the primary generation resources in the subregion. 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 do not significantly impact fuel planning.

The Desert Southwest subregion is a net exporter with forecasted exports expected to remain relatively constant throughout the assessment period. These exports may be curtailed, as needed and as contractually allowed, if peak demand is higher than expected.

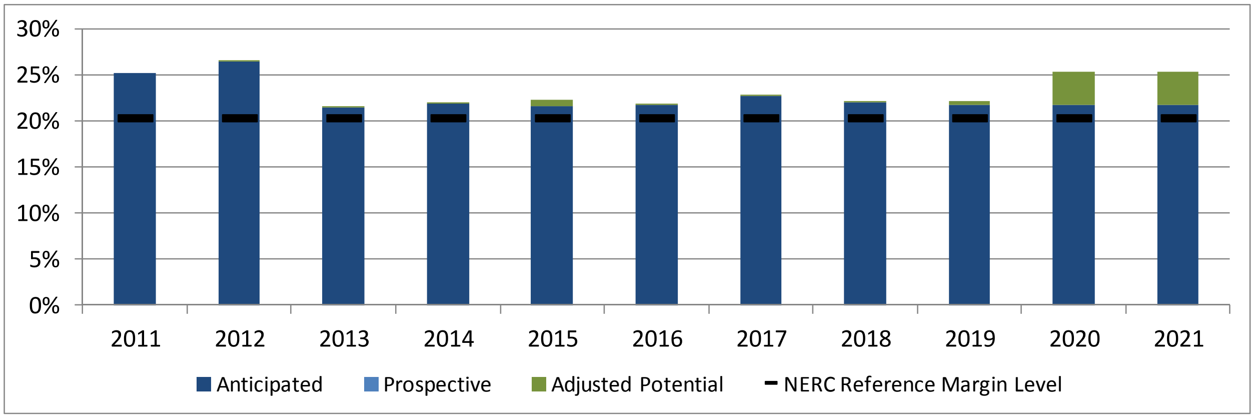
[344] Arizona Incentives/Policies for Renewables & Efficiency: http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&state=AZ.

[345] The New Mexico Public Regulation Commission (PRC) website: http://www.nmprc.state.nm.us/renewable.htm.

Northwest (NORW)

The Northwest subregion target Reserve Margins are 17.2 percent for the summer and 20.3 percent for the winter. The projected Anticipated Resources Reserve Margin ranges between 21.5 and 26.4 percent and does not fall below the target margin during either the summer or winter of the assessment period (Figure 132).

Figure 132: Annual On-Peak Planning Reserve Margins – NORW



It is expected that WECC's probability planning process will investigate the complex relationships between the Northwest hydro short-term maximum capacity ratings and regional energy requirements under normal and adverse weather and water flow assumptions.

Of the existing wind resources within WECC, the Northwest subregion has 5,226 MW, which is derated to 119 MW during the summer peak period.

The subregion has not established a process for assessing resource adequacy. However, individual entities within the subregion have addressed resource adequacy as a part of either their integrated resource planning process or other similar process.

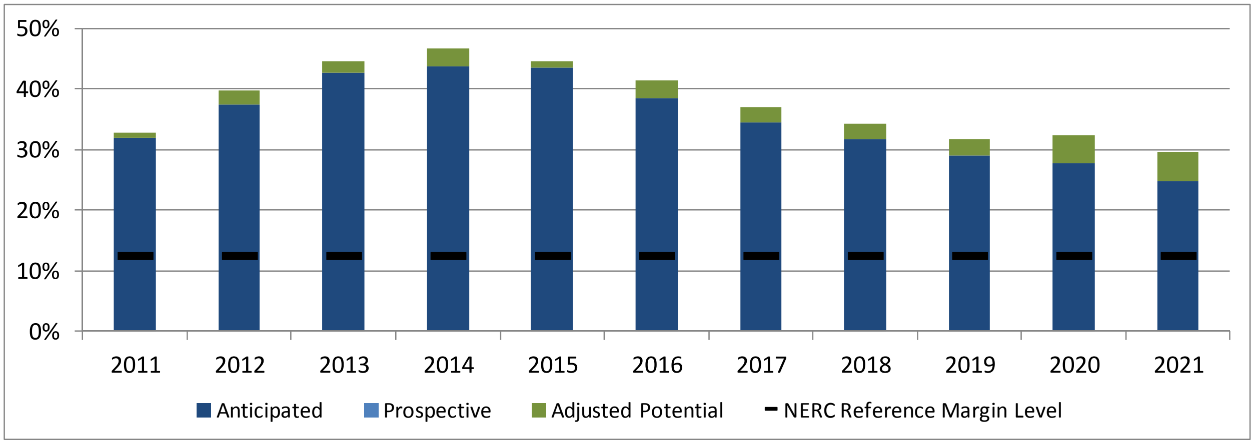
Wind generation has increased rapidly in the Northwest subregion. Since wind resources exhibit output fluctuations, BAs with relatively large amounts of wind generation are pursuing various processes to optimize integrating growing wind resources into the power grid, while also maintaining control over essential power system parameters. Of particular note in this regard is the imposition of wind generation curtailments during light load periods accompanied by high Columbia River hydro generation.

The Northwest subregion is a net exporter with forecasted exports expected to remain relatively constant throughout the assessment period. These exports may be curtailed, as needed and as contractually allowed, if peak demand is higher than expected.

Rockies (ROCK)

The Rockies subregion target Reserve Margins are 12.5 percent for the summer and 13.9 percent for the winter. The Anticipated Resources Reserve Margins are not projected to fall below the target margins during the assessment period (Figure 133).

Figure 133: Annual On-Peak Planning Reserve Margin – ROCK



Of the existing wind resources within WECC, the Rockies subregion has 1,120 MW, which is derated to 164 MW during the summer peak period.

The subregion has not established a process for assessing resource adequacy. However, individual entities within the subregion have addressed resource adequacy as a part of either their integrated resource planning process or other similar process.

Coal, hydro, and gas-fired plants are the primary generation resources in the Rockies subregion. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants may experience operational limitations due to variations in precipitation. As in the Northwest subregion, 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.

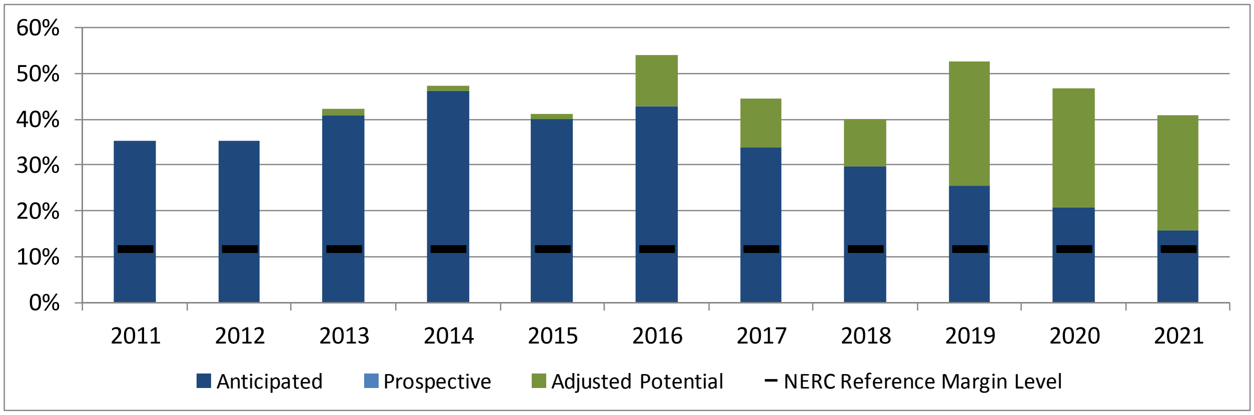
The Colorado RPS for municipal utilities is an annual energy mandate of: one percent of retail sales by 2008; three percent by 2011; six percent by 2015 and 10 percent by 2020. The Public Service Company of Colorado (PSCo) has conducted Effective Load Carrying Capability (ELCC) studies for wind and solar variable resources. The wind ELCC study was completed in late 2006 and concluded that a reasonable capacity value for wind was 12.5 percent of nameplate capacity. The solar ELCC study was filed with the Colorado PUC in December 2008. The study concluded that the reasonable capacity value for solar varies between 60 and 80 percent depending on the location and type of solar resource. The PSCo uses a 70 percent capacity value for its solar resources.

The Rockies subregion is a net importer with forecasted imports expected to remain constant throughout the assessment period.

WECC-Mexico (MEXW)

The WECC-Mexico subregion target Reserve Margins are 11.9 percent for the summer and 10.6 percent for the winter. The Anticipated Resource Reserve Margins are not projected to fall below the target Reserve Margins during the assessment period (Figure 134)

Figure 134: Annual On-Peak Planning Reserve Margins – MEXW



Of the existing wind resources within WECC, the WECC-Mexico subregion has 10 MW, which is derated to 4 MW during the summer peak period. The subregion has not established a process for assessing resource adequacy.

WECC-Mexico is highly reliant on gas-fired and geothermal resources. The WECC-Mexico subregion has a couple of pipeline interconnections with the United States and has a liquefied natural gas (LNG) terminal near Ensenada. Fuel availability for electric power generation is not expected to be an issue during the planning horizon.

The subregion is currently a periodic net power importer; however, more renewable resources come online, it may become an exporting subregion.

Demand

The projected aggregate of 2011 and 2021 summer Total Internal Demand forecasts and growth rates can be seen below (Table 127). The summer Total Internal Demand is projected to increase by 1.54 percent per year during the period of assessment.

Table 127: On-Peak Season Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	149,714	177,123	27,409	1.54%	18.3%
Net Internal	145,285	171,893	26,608	1.54%	18.3%

WECC staff specifically requests its BAs to submit forecasts with a one-year-in-two (50/50) probability of occurrence. Most entities based their forecasts on population growth, economic conditions, and normalized weather. WECC has not established a quantitative analysis process for assessing the variability in projected demands due to the economy, but most of the forecast submissions took into consideration the current economic recession. WECC staff does not perform independent load forecasts. The peak demand forecasts presented here are based on coincident sums of the forecasted demands submitted by WECC's 37 BAs.

Energy Efficiency programs vary by location and are generally offered and administered by LSEs. Programs include ENERGY STAR builder incentive, business lighting rebate, retail compact fluorescent light bulb, home efficiency assistance, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing and water systems. For purposes of verification, some LSEs retain independent third parties to evaluate their programs.

Within the WECC Assessment Area, there is a mixture of Demand Response programs. These programs usually fall into two categories: 1) Passive Demand-Side Management (DSM) programs, and 2) Active DSM programs. A key difference between the categories lies in whether the program is controllable or dispatchable by the LSE or BA. Passive DSM programs are not dispatchable and largely consist of Energy Efficiency programs. Active DSM programs are dispatchable and include Direct Control Load Management (DCLM), interruptible tariffs, and demand-bidding programs. The review, measurement, and verification of the DSM programs are the responsibility of the individual BAs or LSEs, and some entities present results to respective state public utility commissions (PUC). As with Energy Efficiency programs, some entities retain independent third parties to evaluate their programs. LSEs within WECC do not use DSM for meeting RPS requirements.

It is important to consider that not all DSM programs are totally controllable by the BA. Some programs are controlled by the individual LSEs and could be operated without the BAs knowledge. Some programs are customer controlled with penalties for not complying with demand reduction requests by the BA.

The Total Internal Demand forecast for WECC includes summer Demand Response that is projected to increase from 4,429 MW in 2011 to 5,230 MW in 2021. WECC's DCLM capability is located mostly in California.[346] DSM programs, especially air conditioner cycling programs, are also becoming more prevalent in other subregions. Contractually Interruptible (Curtailable) load programs focus on the demand of large water pumping or industrial operations such as mining and amount to 1,697 MW in 2011, growing to 1,839 MW in 2021. On-peak DSM and Energy Efficiency programs for the entire WECC Assessment Area are presented below (Table 128).

[346] 2,464 MW in 2011 and 3,540 MW in 2021.

Table 128: On-Peak Energy Efficiency and Demand-Side Management

Demand Response Category	2011 (MW)	2021 (MW)	Total Change (MW)
Energy Efficiency (New Programs)	**680**	**3,661**	**2,981**
Non-Controllable Demand-Side Management	**-**	**-**	**-**
Direct Control Load Management	1,932	2,068	136
Contractually Interruptible (Curtailable)	1,697	1,839	142
Critical Peak-Pricing (CPP) with Control	3	23	20
Load as a Capacity Resource	797	1,300	503
Total Dispatchable, Controllable Demand Response	**4,429**	**5,230**	**801**
Total Demand-Side Management	**5,109**	**8,891**	**3,782**

The BAs and LSEs use various peak forecasting methods. Several of the entities use various weather scenarios[347] for other internal planning purposes. Econometric models used by various entities within the Western Interconnection consider factors such as certain rate change impacts and average area population income. WECC staff does not prepare quantitative evaluations regarding variability in projected demand due to non-weather factors.

Subregional Demand

Alberta, Canada (AESO)

Alberta, Canada is a winter-peaking subregion. For this assessment period, winter Total Internal Demand is projected to grow at an annual compound rate of 3.71 percent (Table 129).

Table 129: On-Peak Demand – AESO

Demand	2011 (MW)	2021 (MW)	Total Growth (MW)	Average Annual Growth (%)	Assessment Period Change (%)
Total Internal	10,261	15,315	5,054	3.71%	49.3%
Net Internal	10,142	15,252	5,110	3.78%	50.4%

Basin (BASN)

The Basin subregion is summer-peaking and is comprised of the entire state of Utah, as well as most portions of Idaho, Nevada, and Wyoming. For this assessment period, the summer Total Internal Demand is projected to grow at an annual compound rate of 1.64 percent (Table 130).

Table 130: On-Peak Demand – BASN

Demand	2011 (MW)	2021 (MW)	Total Growth (MW)	Average Annual Growth (%)	Assessment Period Change (%)
Total Internal	14,269	17,070	2,801	1.64%	19.6%
Net Internal	13,219	15,946	2,727	1.72%	20.6%

[347] Typically one-year-in-five or one-year-in-ten projections.

British Columbia (BC)

British Columbia, Canada is a winter-peaking subregion. For the period from 2011 through 2021, winter Total Internal Demand is projected to grow at an annual compound rate of 0.76 percent (Table 131).

Table 131: On-Peak Demand – BC

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	11,106	12,077	971	0.76%	8.7%
Net Internal	10,987	12,014	1,027	0.82%	9.3%

California-North (CALN)

The California-North subregion encompasses the portion of California served by the Balancing Authority of Northern California (BANC) BA, the Turlock Irrigation District (TID) BA, and the portion of the California Independent System Operator BA encompassing the Pacific Gas & Electric Company (PG&E) electric transmission grid.[348] For the period from 2011 through 2021, summer Total Internal Demand is projected to grow at an annual compound rate of 1.35 percent (Table 132).

Table 132: On-Peak Demand – CALN

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	25,116	29,106	3,990	1.35%	15.9%
Net Internal	24,258	28,128	3,870	1.35%	16.0%

California-South (CALS)

The California-South area encompasses the portion of California served by the Imperial Irrigation District BA, the Los Angeles Department of Water and Power BA, and the portion of the California Independent System Operator BA encompassing the San Diego Gas and Electric Company (SDG&E) and Southern California Edison Company electric transmission grids.[349] For the period from 2011 through 2021, summer Total Internal Demand is projected to grow at an annual compound rate of 1.61 percent (Table 133).

Table 133: On-Peak Demand – CALS

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	32,661	38,947	6,287	1.61%	19.2%
Net Internal	31,055	36,385	5,331	1.45%	17.2%

[348] This area is also known as the North of Path 26 area.

[349] This area is also known as the South of Path 26 area.

Desert Southwest (DSW)

The Desert Southwest subregion consists of Arizona, most of New Mexico, southern Nevada, and the westernmost part of Texas. For the period from 2011 through 2021, summer Total Internal Demand is projected to grow at an annual compound rate of 1.77 percent (Table 134).

Table 134: On-Peak Demand – DSW

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	28,308	34,336	6,028	1.77%	21.3%
Net Internal	27,848	34,193	6,345	1.88%	22.8%

Northwest (NORW)

The Northwest is a winter-peaking subregion, comprised of all of the states of Oregon and Washington, and portions of the states of California, Idaho and Montana. For the period from 2011 through 2021, winter Total Internal Demand is projected to grow at an annual compound rate of 0.89 percent (Table 135).

Table 135: On-Peak Demand – NORW

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	29,468	32,483	3,014	0.89%	10.2%
Net Internal	29,425	32,418	2,992	0.88%	10.2%

Rockies (ROCK)

The Rockies subregion consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The Rockies subregion may experience its annual peak demand in either the summer or winter season.[350] For the period from 2011 through 2021, summer Total Internal Demand is projected to grow at an annual compound rate of 2.02 percent (Table 136).

Table 136: On-Peak Demand

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	10,973	13,677	2,704	2.02%	24.6%
Net Internal	10,576	13,352	2,776	2.14%	26.2%

WECC-Mexico (MEXW)

The WECC-Mexico subregion encompasses the northern portion of Baja California, Mexico. For the period from 2011 through 2021, summer Total Internal Demand is projected to grow at an annual compound rate of 4.05 percent (Table 137).

[350] The Rockies subregion was assumed to the summer-peaking for this assessment.

Table 137: On-Peak Demand – MEXW

Demand	2011	2021	Total Growth	Average Annual Growth	Assessment Period Change
	(MW)	(MW)	(MW)	(%)	(%)
Total Internal	2,190	3,389	1,199	4.05%	54.7%
Net Internal	2,190	3,389	1,199	4.05%	54.7%

Generation

The generation data for this assessment was provided by all of BAs within the Western Interconnection and was processed by WECC staff under the direction of the WECC Loads and Resources Subcommittee. The BAs classified each generator as *Existing-Certain* (EC), *Existing-Other* (EO) *Future-Planned* (FP), *Future-Other* (FO), or *Conceptual*, based on the NERC resource definitions. The reported generation additions generally reflect extraction from generation planning queues.

The generation resources for the assessment period in are shown below (Figure 135 and Figure 136). Distributed generation, including roof-top solar and behind-the-meter generation, represent an insignificant portion of both the existing and planned resources. As noted previously, these types of generation are excluded from the resource adequacy calculation (*i.e.,* they are not included as resources).

Figure 135: On-Peak Capacity Mix by Fuel Type

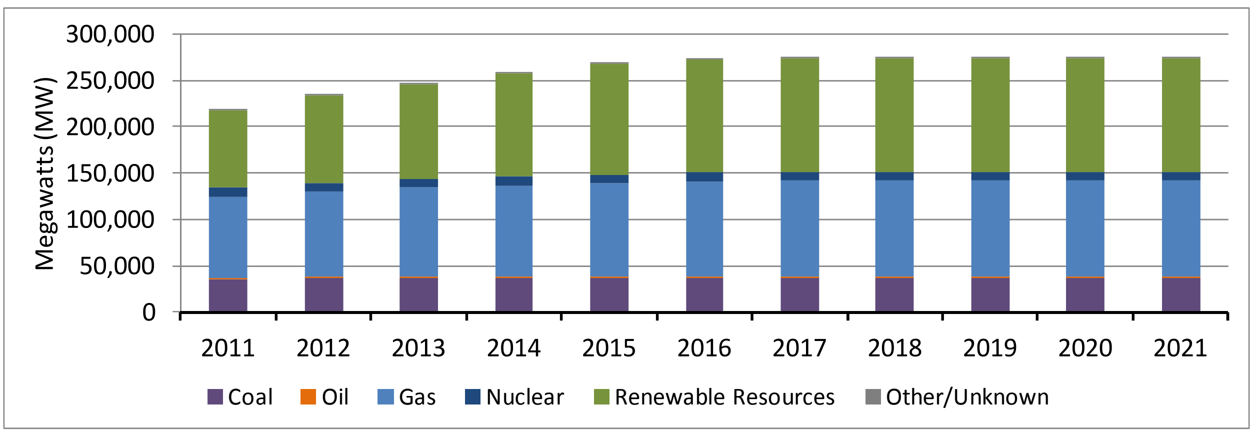
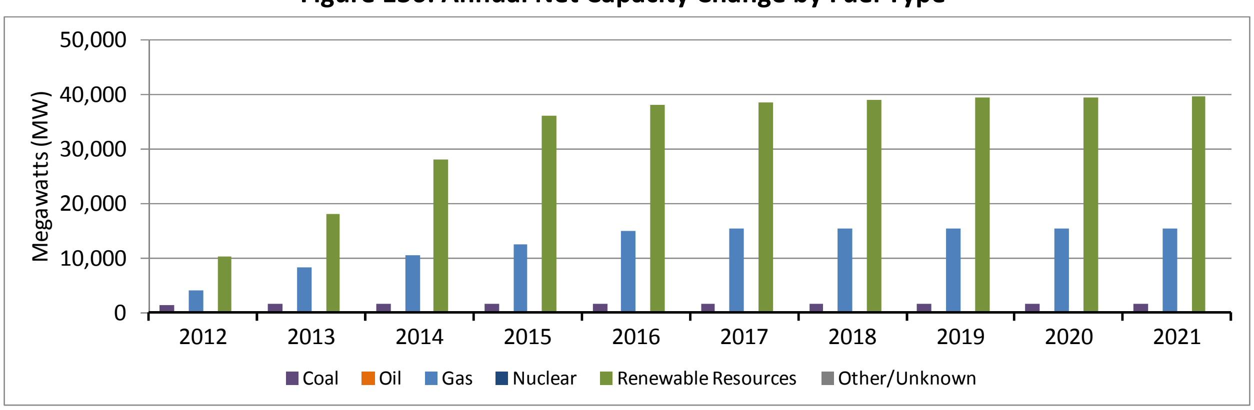


Figure 136: Annual Net Capacity Change by Fuel Type



The projected summer peak resources value for July 2011 of 201,294 MW reflects the monthly shaping of variable generation and the seasonal ratings of conventional resources. The resources not counted toward on-peak capacity include 31,251 MW of variable generation derates and 7,018 MW of Scheduled Outages. Additionally, hydroelectric resources have been derated to reflect adverse hydro conditions. The net FP capacity resources projected to be in-service by the end of this assessment period, as reported by the individual BAs, total 54,416 MW. A breakdown of renewable resources with associated capacities is shown below (Table 138).

Table 138: On-Peak Expected and Derated Renewable Resources

Renewable Resource		2011 (MW)	2021 (MW)	Total Change (MW)
Wind	Expected	3,488	17,933	14,445
	Derated	9,311	16,211	6,900
	Wind - Total Nameplate Capacity	**12,799**	**34,144**	**21,345**
Solar	Expected	603	27,218	26,615
	Derated	58	1,424	1,366
	Solar - Total Nameplate Capacity	**661**	**28,642**	**27,981**
Hydro	Expected	48,563	49,131	568
	Derated	20,883	24,366	3,483
	Hydro - Total Nameplate Capacity	**69,446**	**73,497**	**4,051**
Biomass	Expected	1,127	1,681	554
	Derated	409	435	26
	Biomass - Total Nameplate Capacity	**1,536**	**2,116**	**580**

The NERC Reliability Assessment Subcommittee (RAS) has requested that the BAs provide a pair of confidence factors. One is applied to the *Future-Other* resources and the other is applied to the *Conceptual* resources. Using the confidence factors from the BAs, Regional and subregional confidence factors are developed. The total potential capacity and the projected on-peak capacity of FO resources, without applying the confidence factor, are zero as no resource additions were classified as FO for this year's assessment. The total potential capacity and the potential on-peak projected capacity of *Conceptual* resources are 17,992 MW and 10,147 MW, respectively. The adjusted on-peak potential of 10,147 MW reflects the application of a 100 percent aggregate confidence factor. These adjusted totals are used by WECC's resource allocation model to determine the projected diversity exchanges, and the resulting margins presented in this assessment.

The building block values were developed for each BA and then aggregated by subregion and for the entire WECC Region. The aggregated summer season target margin for WECC is 14.2 percent. These Reserve Margins were developed specifically for use in NERC's LTRAs and WECC's PSAs, and may be lower or higher than some of the state, provincial, or LSE requirements within WECC. These target margins are not requirements for the WECC BAs to meet, but are only used for reporting purposes.

The 37 BAs in WECC use a variety of methods to determine their future resource requirements. Many entities file an Integrated Resource Plan with their state regulators to establish the need for resources in order to maintain planning Reserve Margins or to meet state or local requirements. Some of the processes used to quantify the need for more resources include: forward capacity markets and resource adequacy needs, obligation to serve activities, and the certainty of resources under consideration. The selection of additional resources often includes an evaluation of fuel diversity, environmental impacts, or the need to add new generation to meet renewable portfolio standards. In addition, some entities use optimization programs to help select the best portfolio of future resources, minimize the amount of energy not served, or solve for a desired loss of load probability. To secure the identified additional resources, many entities within WECC use formal Requests for Proposals or rely on market price signals to spur development of the resources.

Individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure can be viewed on the WECC website.[351] 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.

Because the transfers between subregions are calculated using the projected capability of wind generators at the time of peak, additional transfers from wind or other generation may be blocked by inadequate transmission capacity during other hours. The extent of these additional potential transfers is unknown and was not considered for this assessment, or for the PSA analysis. WECC has established a Variable Generation Subcommittee[352] that parallels NERC's Integration of Variable Generation Task Force IVGTF, to examine issues related to planning for and operating with large amounts of variable generation on the system.

WECC staff does not conduct a formal fuel supply interruption analysis; however, these types of studies are performed by individual entities within WECC. 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 the plant owners actually own the mines. This pattern is less true for newer plants or those proposed for possible development after 2011. Gas-fired generation is typically located near major load centers and relies on relatively abundant western gas supplies. In addition, some of the older gas-fired generators in the Region have backup fuel capability and normally carry an inventory of backup fuel. WECC does not require verification of the operability of the backup fuel systems and does not track on-site backup fuel inventories. Most of the newer generators are strictly gas-fired, which has increased the Region's exposure to interruptions to that fuel source.

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

[351] Overview of Policies and Procedures for Project Coordination Review, Project Rating Review, and Progress Reports: http://www.wecc.biz/committees/StandingCommittees/PCC/Shared%20Documents/ProjectCoordination_ProjectRating_ProgressReports_approved%203-11.pdf.

[352] WECC's Variable Generation Subcommittee: http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/default.aspx.

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

Some of the WECC entities have taken steps to mitigate possible fuel supply vulnerabilities through 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 times of possible adverse hydro conditions.

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

Capacity Transactions

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins. Neither does the Region model exports to areas outside of WECC. However, imports may be scheduled across three back-to-back DC ties with the Southwest Power Pool, Inc. (SPP) and five back-to-back DC ties with the Midwest Reliability Organization (MRO). One WECC entity reports a diversity exchange credit with its counterpart in SPP.

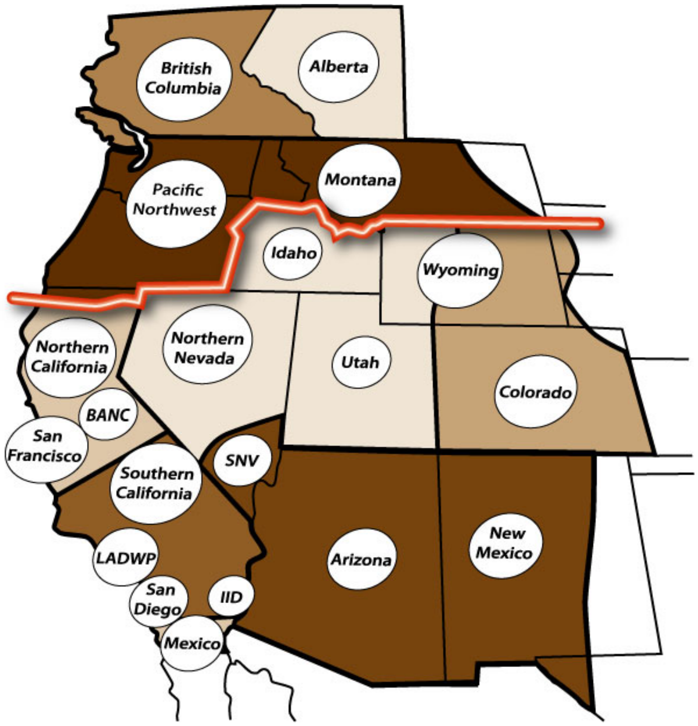
Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC. The WECC resource allocation model places conservative transmission limits on paths between 20 load groupings (bubbles) when calculating the transfers between these areas. These load bubbles were developed for WECC's PSA studies. The aggregation of PSA load bubbles into WECC subregions may obscure differences in adequacy or deliverability between bubbles within the subregion. These transfers were submitted to NERC as Firm and projected transactions that are dependent upon the magnitude of the reported *Future-Planned* resources. Hence, the resource data for the individual subregions include transfers between subregions that are either plant-contingent transfers or reflect projected economic transfers with a high probability of occurrence. The plant-contingent transfers represent both joint-plant ownership and plant-specific transfers from one subregion to another.

The projected economic transfers reflect the potential use of seasonal demand diversity between the winter-peaking Northwest and the summer-peaking Southwest, as well as other economy and short-term Firm purchases that may occur between subregions.

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

A process similar to the one used to determine Regional and subregional target margins was used to determine the inter-subregional transfers. The various area bubbles used were combined into the appropriate WECC subregions (Figure 137) and the excess or deficit capacity was summed for each of the WECC subregions. The excess/deficit capacity was then used to calculate the amount of projected purchases or projected sales transactions between the various subregions.

Figure 137: 2011 WECC Assessment Area Subregions



WECC's resource allocation modeling indicates possible congestion within some of WECC's subregions due to economic diversity exchanges. As an example, a condition called the "North-South split" traditionally occurs when the transmission ties between the California-Oregon Border, Pacific Northwest, British Columbia, and Montana (the North) and the areas to the south have insufficient transfer capability to allow all surpluses in the north to serve loads south of the constraint. In the past, the North-South split usually occurred within the Northwest subregion. With the projected resource additions and updates to the transmission system, the split sometimes drops lower into central California and the Rockies. Utah, in all cases, was south of the North-South split.

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

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

Transmission

The WECC Region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the Region is winter peaking while the southern portion of the Region is summer peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. These conditions result in periodic full loading on numerous transmission lines but that full loading is deemed as not adversely impacting reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

For the 2011 to 2021 period, 15,258 circuit miles of 100 through 500 kV AC and 3,095 circuit-miles of DC transmission line additions have been reported to WECC. There are a large number of transmission projects that have been reported to WECC. Some of these projects are duplicative in nature and may have a proposed path similar to another project. Since WECC does not vet the reported new projects and does not identify minimum transmission addition needs, the above tabulation may not closely reflect transmission additions that could occur during the assessment period. A delay of these projects could impact the timing and location of resource additions but should not adversely impact system reliability. The subregion sections of this assessment may identify some projects that could impact local area reliability. The WECC Transmission Project Information Portal[353] provides a single location where interested parties can find basic information about major transmission projects in the Western Interconnection.

WECC's Transmission Expansion Planning Policy Committee's Subregional Coordination Group has analyzed the development status of known major transmission projects and identified 44 projects that have a high probability of being constructed over the next 10-years. Thirty of those projects are at 345 kV or higher and three (Montana to the Northwest and Northwest to California AC and DC) involve congested transmission paths. WECC's first-ever Interconnection-wide transmission plan recommends priority consideration by decision-makers for transmission upgrades or other mitigating measures that relieve congestion on these three transmission paths.

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in WECC's *Policies and*

[353] WECC Transmission Project Information Portal: http://www.wecc.biz/PLANNING/TRANSMISSIONEXPANSION/MAP/Pages/default.aspx.

Procedures for Project Coordination Review, Project Rating Review, and Progress Reports.[354] 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.

WECC has signed an agreement with the U.S. Department of Energy to receive a $53.9 million grant for the Western Interconnection Synchrophasor Program (WISP). The funding allows an accelerated installation of more than 250 new Phasor Measurement Units in the Western Interconnection. The Phasor Measurement Units are designed to alert operators to existing and potential problems on the grid and improve the ability to integrate and manage intermittent renewable resources in the West. The synchrophasor infrastructure and associated software applications and tools are expected to improve situational awareness, system-wide modeling, performance analysis, and wide-area monitoring and controls. Further information regarding the WISP program is available on the WECC website.[355]

Subregional Transmission

Alberta, Canada (AESO)

The growth in demand, combined with increases in projected new generation has resulted in the need for significant transmission system upgrades and expansion. Because of the longer time required for transmission permitting and construction, network planning focuses on establishing a flexible grid infrastructure. This is being done with the goals of accommodating internal power movement from generation sites to load centers.

Planning efforts continue on a number of major system reinforcements including supply into the Fort Saskatchewan and Fort McMurray areas of Northeast Alberta. This reinforcement will likely be a combination of 500 kV and 240 kV developments. Planning efforts are also continuing on reinforcing the main north–south transmission grid in Alberta. The Edmonton-to-Calgary Transmission Reinforcement project calls for two high-capacity lines between the north and south of the province to reinforce the backbone of the grid. It is anticipated this project will be in-service by the end of 2014.

Alberta Electric System Operator has an under-voltage load shedding (UVLS) scheme. There are approximately 300 MW currently connected to the UVLS, which will not impact the reliability of the AESO subregion.

A Calgary-area transmission must-run procedure addresses 240 kV transmission grid-loading issues and ensures voltage stability margins are maintained. The transmission must-run procedure is an ancillary service contract with generators that is required to address contingencies in areas of inadequate

[354] WECC's Overview of Policies and Procedures for Project Coordination Review, Project Rating Review and Progress Reports: http://www.wecc.biz/committees/StandingCommittees/PCC/Shared%20Documents/ProjectCoordination_ProjectRating_ProgressReports_approved%203-11.pdf.

[355] WECC WISP web site: http://www.wecc.biz/awareness/Pages/WISP.aspx.

transmission to help provide voltage support to the transmission system in southern Alberta, near Calgary, and assist in maintaining overall system security.

Basin (BASN)

Transmission owners in the subregion have started construction on significant grid reinforcements and enhancements to support intra-regional power transfers and exports of wind generation.

Power flow studies have been conducted by the transmission planning authorities and in some cases where there have been N-1 and N-2 critical contingencies identified, mitigation measures (*e.g.,* adding reactive sources) or new facilities (*e.g.,* adding a new transformer) have been proposed. Because some of these improvements are driven by future load growth or 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.

British Columbia, Canada (BC)

Because of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goal of accommodating internal power movement from generation sites to load centers.

Analysis of WECC's 2010 PSA results indicates that economic diversity exchanges may result in full loading of the transmission interconnections between the United States and Canadian portions of the NWPP during winter peak periods. The BC subregion is traditionally a net exported with forecasted exports expected to remain relatively constant throughout the study period.

The BC subregion relies on hydroelectric generation for 90 percent of its energy production. British Columbia Hydro and Power Authority (BCHA) is responsible for the planning, operation, and maintenance of British Columbia's publicly-owned transmission system. BCHA is addressing constraints between remote hydro plants and the Lower Mainland (LM) and Vancouver Island (VI) load centers.

A key transmission shortage that faces the BC subregion currently is the Interior-to-Lower Mainline path. The Interior-to-Lower Mainland (ILM) Transmission Project[356] is the largest expansion project in 30 years for the province. In August 2008, the BC Utility Commission approved the ILM Project, which is a new 500 kV line between the Nicola and Meridian substations, with a projected in-service date in 2014.

BCHA is planning to rely on the existing 905 MW conventional steam plant located in the major load center and the 1,250 MW Canadian entitlement from the NWPP U.S. to meet the Lower Mainland resource requirements in the interim period.

BCHA has UVLS schemes installed for the Lower Mainland and Vancouver Island systems to prevent voltage collapse. These schemes monitor the voltage at the key substations in Vancouver Island and

[356] Interior to Lower Mainland (ILM) Transmission Project: http://transmission.bchydro.com/projects/ilm/.

Lower Mainland, and the VAr reserves at Vancouver Island transmission synchronous condensers and Burrard generation station. If the voltages and the VAr reserves are lower than the settings, the selected loads in Vancouver Island and Lower Mainland will be shed. The maximum load-shedding amount is about 1,690 MW. BCHA is not expecting to install additional UVLS.

California-North (CALN)

The 500 kV bulk transmission systems in northern California consist of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue south to the Vincent substation. This system transfers power between California and other states in the Northwest. The interconnection at the northern end is identified as Path 66 or the California-Oregon Intertie. The system also interconnects with northern California hydroelectric generation for delivery to population centers in the San Francisco Bay area and the Central Valley area. Further south, the 500 kV lines interconnect with a large number of generation resources in central California. At the Vincent substation, the 500 kV lines interconnect with the Southern California Edison 500 kV transmission system. That interconnection point is identified as Path 26.

The Reliability Assessment section of the CAISO's 2010-2011 Transmission Plan[357] examined power flow studies, transient stability analysis, and voltage stability studies to identify facilities that indicate a potential of not meeting applicable performance requirements. For the backbone system assessment (500 kV and select 230 kV facilities), conventional and governor power flow studies and stability studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for eight local PG&E service territory areas. The transmission plan approved 23 reliability-driven transmission projects. All but two of the approved projects were for facilities rated at less than 230 kV.

California-South (CALS)

As noted in the California-North assessment, the California-South subregion is connected to the California-North subregion by three 500 kV transmission lines. Additional California-South interconnections include a 500 kV DC transmission line to north central Oregon, a 500 kV DC transmission line to the Intermountain Power Plant in central Utah, a few 230 kV ties to Baja California, Mexico, and numerous 500 kV and lower voltage ties to Arizona and southern Nevada. These numerous interconnections allow the subregion to be a net importer of significant amounts of power.

Desert Southwest (DSW)

Transmission providers from the Desert Southwest subregion, along with other stakeholders from southern California, are actively engaged in the Southwest Transmission Expansion Planning (STEP) group. The goal of this group is to collaborate in the planning, coordination, and implementation of a

[357] CAISO 2010-2011 Transmission Plan: http://www.caiso.com/2b88/2b8872c95ce10.pdf.

robust transmission system interconnecting Arizona, southern Nevada, Mexico, and southern California that is capable of supporting a competitive, efficient, and seamless West-wide wholesale electricity market while meeting established reliability standards. The STEP group has developed three projects resulting from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades was completed in 2006 and increased the transfer capacity by 505 MW. The second set of upgrades was to increase the transfer capacity by 1,245 MW and many have been completed. The third and last set of upgrades is the Palo Verde to Devers #2 500 kV transmission line (PVD2). This third set of upgrades as proposed by the STEP group developed complications in 2007 with the Arizona Corporation Commission's refusal to grant a permit for the construction of the PVD2 line, which may cancel or delay the construction of the line. In May 2009, Southern California Edison (SCE) dropped the Arizona portion of the proposed line and announced that it would proceed to construct the California portion in 2010. During the years that the line has been proposed the resource situation changed drastically and the SCE now believes that the California portion of the line is useful for central station solar projects being planned for the eastern portion of the state.

Northwest (NORW)

For the Northwest subregion, additional time required for transmission permitting and construction requires added recognized that network planning should focus on establishing a flexible grid infrastructure. This is being accomplished with the goals of accommodating anticipated transfers among systems, addressing several areas of constraint within Washington, Oregon, Montana, northern Idaho, and other areas within the Region, and integrating new generation. Projects at various stages of planning and implementation include approximately 1,657 miles of 500 kV transmission lines.

Maintaining the capability to import power into the Northwest subregion during infrequent extreme cold weather periods continues to be an important component of transmission planning and operations. In order to support maximum import transfer capabilities under double-circuit simultaneous outage conditions, the Northwest subregion depends on an automatic under-frequency load shedding (UFLS) scheme.

Some BAs have taken steps to help make the transmission queue and transmission queue assessment processes more efficient. For example, BPA instituted a process called the Network Open Season (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) that 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.

Rockies (ROCK)

Tri-State Generation and Transmission is proposing a project in southern Colorado called the San Luis Valley Electric System Improvement project. The project would involve the construction of an 80 mile

230 kV transmission line between the Walsenburg substation and the San Luis Valley substation. The San Luis Valley's existing electrical system has reached its limit due to continued residential and irrigation growth. One major concern is 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 MW. This line will provide the power delivery infrastructure to increase the reliability and capacity of the existing transmission system and support proposed renewable energy development in the area.

The Western Area Power Administration (WAPA) is upgrading several 115 kV transmission lines to 230 kV over the next several years to increase transfer capabilities and help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado.

WECC-Mexico (MEXW)

There were no significant transmission additions in the WECC-Mexico subregion.

Operational Issues

Under WECC's current Regional Reliability Plan, two reliability coordination offices have been established for the WECC Region, one in Colorado and one in Washington. The reliability coordinators (RC) are charged with actively monitoring, on a real-time basis, the interconnected system conditions to anticipate and mitigate potential reliability problems and to coordinate system restoration, should an outage occur. The RCs currently use the West-wide System Model, which is an energy management system that allows monitoring of the electrical grid and provides contingency analysis, but does not allow any control.

Most of the BAs in WECC establish planning Reserve Margins that account for temperature extremes. The target Reserve Margins developed for this assessment use a 1-in-10 weather event as the proxy for extreme temperature conditions. However, if operating reserves decline below minimum required levels, operators could call on their various DSM programs, request public Conservation, attempt to purchase power, and — as a last resort — initiate rolling Firm load interruptions.

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

The integration of increasing levels of variable generation resources, specifically wind and solar, that are required to meet state or local RPSs has led BAs to adjust their operations to accommodate the intermittency of the generation from these resources. The variable resources place an increased demand on the traditional resources used to balance their systems. BAs have relied on better wind forecasting programs, increased spinning reserves, and have developed other methods to mitigate undesirable impacts on their systems. As mentioned earlier, WECC has established the Variable

Generation Subcommittee to help examine issues related to planning for and operating with large amounts of variable generation.[358]

Historically, the projected retirement of existing generation has been associated with the construction of replacement resources, thus minimizing any adverse impact from retirements. Environmental issues regarding once through cooling and coal-fired plant emissions, however, have a potential to result in plant closures at a pace that temporarily exceeds the startup of replacement generation. While the planning margin information presented in this assessment may indicate some flexibility in accommodating a nominal amount of unexpected plant closures, a near simultaneous loss of significant generation due to environmental issues could result in a substandard level of reliability.

WECC staff does not foresee any significant operational problems or integration concerns with regard to renewable distributed generation systems, such as rooftop solar panels, nor does WECC staff foresee any reliability concerns resulting from high levels of demand response resources.

NERC standards require Regional Reliability Organizations to have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations, with the intent that such a procedure will result in a reduction of the amount and severity of protective system misoperations. WECC's Relay Work Group has prepared a procedure that addresses analysis of misoperations of transmission and generation protection.[359]

Subregional Operational Issues

Alberta, CA (AESO)

The AESO subregion has experienced significant growth in wind resources and expects that growth to continue. Although wind integration may pose issues at some point, there are no current significant integration issues that adversely impact system reliability. While under normal weather conditions it is not anticipated that the AESO subregion will depend on imports from external areas during winter peak demand periods, under extreme weather conditions the AESO subregion may need to increase diversity exchange imports.

Basin (BASN)

As in the WECC-Canada and Northwest subregions, growth in wind-powered generation in portions of the subregion has affected short-term scheduling procedures and continued growth in wind generation is expected to further impact power scheduling processes.

[358] WECC's Variable Generation Subcommittee: http://www.wecc.biz/committees/StandingCommittees/JGC/VGS/default.aspx.

[359] WECC Procedure for Analysis of Misoperations of Transmission and Generation Protection: http://www.wecc.biz/Standards/Development/WECC-0059/Shared%20Documents/Relay%20Misoperation%20 Procedure%204-3-09.doc.

British Columbia (BC)

While under normal weather conditions the BC subregion does not anticipate dependence on imports from external areas during winter peak demand periods, under extreme weather conditions, subregion should be able to increase diversity exchange imports.

California-North (CALN)

The CAISO's 2010-2011 Transmission Plan identified numerous performance criteria issues that are to be addressed through operational procedures or special protection schemes, including some instances where operational procedures will be relied on until certain facility improvements are in service.

California-South (CALS)

In order to prevent voltage collapse, California-South electric power imports may at times be limited. This Southern California Import Transmission limitation, which relates to Path 49 (aka East of Colorado River) power flows and internal subregion on-line generator inertia, is studied regularly and routinely monitored by the transmission system operators.

The CAISO's 2010-2011 Transmission Plan[360] identified numerous performance criteria issues that are to be addressed through operational procedures or special protection schemes, including some instances where operational procedures will be relied on until certain facility improvements are in service.

Desert Southwest (DSW)

Special protection schemes play an important role in maintaining system adequacy should multiple system outages occur. These schemes include generator tripping in response to specific transmission line outages. In addition, operators rely on procedures such as operating nomograms so the system can respond adequately to planned and unplanned transmission or generation outages.

Northwest (NORW)

Growth in wind-powered generation in portions of the subregion has affected short-term scheduling procedures and continued growth in wind generation is expected to further impact power scheduling processes. The Northwest has experienced high hydro conditions due to near record spring runoff, and at the same time, increases in off-peak wind production. This combination forced the Bonneville Power Administration (BPA) to curtail wind generation. This treatment of wind generation is being discussed but, as of this time, no resolution to the problem has been reached.

Rockies (ROCK)

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.

[360] CAISO 2010-2011 Transmission Plan: http://www.caiso.com/2b88/2b8872c95ce10.pdf.

WECC Mexico (MEXW)

No operational issues have been identified that would be expected to adversely impact electric power reliability in the region during the long-term planning horizon.

Assessment Area Description

WECC's 329 members, including 37 Balancing Authorities, represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 81 million people, it is the largest and most diverse of the eight NERC Regional reliability organizations.[361]

[361] Additional information regarding WECC can be found on its website: www.wecc.biz.

Appendix I: About this Report

Background

The *2011 Long-Term Reliability Assessment* represents NERC's independent judgment of the reliability of the BPS in North America for the coming 10-years (Table I).[362] The report specifically provides a high-level reliability assessment of the 2011 to 2021 seasonal resource adequacy and operating reliability, an overview of projected electricity demand growth, Regional highlights, and Regional self-assessments.

NERC's primary objective in providing this assessment is to identify areas of concern regarding the reliability of the North American BPS and to make recommendations for their remedy as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations and exchange vital system reliability information. This assessment is prepared by NERC in its capacity as the Electric Reliability Organization.[363] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[364] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

Table I: NERC Assessments

Assessment	Outlook	Publish Target
Summer	Upcoming Season	May
Long-Term	10 Years	Fall
Winter	Upcoming Season	November

Data Checking and Validation

NERC's staff performed detailed data checking and validation on the reference information received from the Regions, as well as review of all self-assessments to form its independent view and assessment of the reliability of the coming 10-years. NERC also uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject-matter expertise from many sectors of the industry. This process also provides an essential check and balance for ensuring the validity of the information provided by the Regional Entities.

NERC's Reliability Assessment Data Validation and Error Checking program was implemented to ensure the Reliability Assessment Database operates with consistent data. It uses routines, often called "validation rules," that check for correctness, meaningfulness, and security of data that are added into the system (Table II).

[362] Bulk power system reliability, as defined in the *How NERC Defines Bulk Power System Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

[363] 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."

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

Table II: NERC Data Quality Framework and Attributes

Data Quality Attribute	Responsible Entity	Data Check Performed
Accuracy	Industry	Validation rules
Ensure data are the correct values		Consistent with other external sources
Accessibility	DCWG, NERC, and RE	Data is submitted in the provided template
Data items should be easily obtainable and in a usable format		
Comprehensiveness	DCWG, RE, and Stakeholders	Check for null values
All required data items are submitted		Compare to prior year's null values
		Inquiries to the RE
Vintage	RE and Stakeholders	Consistent with other external sources
The data should be up-to-date		
Consistency	DCWG, NERC	DCWG leads in this effort
The value of the data should be reliable and the same across different reporting entities		Assumptions are verified with the RE
Definition	DCWG, NERC Staff	DCWG leads in this effort
Clear definitions should be provided so the current and future data users can understand the assumptions		

Internal data checking and validation refers to the practice of validating and checking data through internal processes (*e.g.,* Historical Comparison, Range and Limits, Data Entry Completeness, Correct Summations) to maintain high quality data. The rules are implemented through automated processes — data dictionary for data checking and logic for validation. Incorrect data can lead to data corruption or a loss of data integrity. Data validation verifies it is valid, sensible, and secure before it is processed for analysis. The program uses scripts, developed on a composite Microsoft Excel and Microsoft Access platform, to provide a semi-automated solution.

In addition, NERC's Data Coordination Working Group (DCWG) monitors the quality of data reported. The DCWG serves as a point of contact responsible for supporting NERC staff, continuously maintaining high quality data and provide enhancements to current practices.

Data validation is a process for ensuring correct and useful data. One element of this process is internal data checking and validation — NERC achieves this for assessment reports through a rigorous semi-automated process outlined in the *Data Checking Methods Applied* section of this report. The second element of this process involves comparisons to external sources. Consistent with NERC's role to provide independent and comprehensive assessments of bulk power reliability, this report includes comparisons to external sources for demand and supply forecasts. These external sources include Canadian and United States government agencies, non-governmental organizations, industry working groups, and consultants with expertise in electricity demand or supply forecasting. For a robust comparison base, NERC includes external forecasts developed by complex macroeconomic and power-flow models. NERC staff has reviewed the sources included in this report to ensure that their work is unbiased, reflects current industry practices, and represents acknowledged and credible information.

As an enhancement to future assessments, NERC expects to broaden the list of sources used for comparisons. However, meaningful forecasts in this arena are limited to a narrow group of agencies, organizations, groups, and companies — many of which are already represented here. This is particularly true for electricity demand forecasting. Several organizations producing such forecasts are for-profit companies with proprietary models, restricting the use of their data.

The Data Validation and Error Checking Program also includes limited external validation of transmission projects. NERC uses a news aggregation service to review public news articles, press releases, corporate filings, government filings, and online industry news sources to track the progress of transmission projects. The results of this review are then compared against the transmission project data and information data obtained from Region members, and any resulting inconsistencies are shared with Region members for further examination.

Regions report capacity and demand related to reliability not as a function of an economic model or based on extreme "system stress" case. This generally involves 50/50 demand forecasts and various levels of capacity planning certainty. The forecast values provided below may represent extreme cases based on 90/10 demand forecasts or modeling values, which rely on economic assumptions. Readers are advised to review the assumptions provided for each source to explain any significant differences. Further the inclusion or exclusion of capacity transactions (imports or exports) across NERC Region-geographic boundaries may result in differences between NERC values and external sources. (NERC's capacity values reflect Firm capacity transactions. See *Terms Used in this Report* for details.)

Individual unit data was collected for the first time in 2010 with regions being required supply-level data for individual generating units. Several drivers lead to this enhancement:

- The need to validate capacity and supply data
    - Provide detail and increased granularity of supply data
    - Perform validation between other data sources (*e.g.,* Form EIA-860)
    - FERC request to provide comprehensive data checking and validation
- Reduces data form entry and categorization errors
- Coordination with EIA to develop the 2014 Form EIA-411

In 2012, NERC will begin designing and implementing a comprehensive database to be automatically populated with generation, transmission, and demand data relevant to reliability assessment. NERC will establish a web application to support the collection, validation, and distribution of assessment data.

Report Content Responsibility

In close collaboration with NERC staff, the RAS oversees the preparation of the seasonal and Long-Term Reliability Assessments. The RAS reports to the PC and its members prepare the Regional data and narratives, conduct peer reviews, develop Emerging Issues, and contribute to the report writing and review process. The following NERC industry groups have also collaborated efforts to produce NERC's *2011 Long-Term Reliability Assessment* (Table III):

Table III: NERC Reliability Assessment Contributors

NERC Group	Relationship	Contribution
Board of Trustees (BOT)	NERC's Independent Board of Trustees	Review the *Long-Term Reliability Assessment*
		Approve for publication
Planning Committee (PC)	Reports to NERC's Board of Trustees	Review *Long-Term Reliability Assessment*
		Risk assessment of Emerging/Standing Issues
Operating Committee (OC)	Reports to NERC's Board of Trustees	Review Assessment and provide comments to PC on operational aspects
Energy Ventures Analysis, Inc. (EVA)	Third-Party Independent Consultant	Provide assessment on environmental impacts
Integration of Variable Generation Task Force (IVGTF)	Reports to the PC and the OC	Contribute to Standing Issues
Load Forecasting Working Group (LFWG)	Reports to the RAS	Develop load forecasting bandwidths
Data Coordination Working Group (DCWG)	Report to Data Coordination Subcommittee	Develop data and Regional reliability requests
		Data checking and validation
Eastern Interconnection Reliability Assessment Group (ERAG)	Independent Reliability Group	Contributed to demand data validation effort
Reliability Metrics Working Group (RMWG)	Reports to the PC	Developed System Risk Index
Resource Issues Subcommittee (RIS)	Reports to the PC	Develop Emerging Issues
		Demand resources
Transmission Issues Subcommittee (TIS)	Reports to the PC	Develop Emerging Issues

Appendix II: 2011 Long-Term Reliability Assessment Data and Information Request

The data request letter provided to the Regional Executives in January 2011 included the following instructions:

Regional Self Assessment — 2011 Long-term Reliability Assessment
Prepare a written reliability self assessment narrative for the Region, subregion, or reporting area during the long-term assessment period (2011-2021).

2011 Long-Term Reliability Assessment - Letter to Regional Entity Executives
http://www.nerc.com/docs/pc/ras/2011LTRA_Letter_v5.doc

2011 Long-Term Reliability Assessment - Data Form
http://www.nerc.com/docs/pc/ras/ERO2011LTRA_v2.xls

2011 Long-Term Reliability Assessment - Data Form Instructions
http://www.nerc.com/docs/pc/ras/2011_LTRA_Instructions.xls

Additionally, for 2011, NERC requested additional information from stakeholders, requesting updated resource plans. NERC observed changes in resource plans occurring due to pending and finalized environmental rules. The information request on the next page reflects this data request.

August 5, 2011

TO: Regional Executives
CC: Gerry Cauley
ERO-RAPA
Reliability Assessment Subcommittee
Planning Committee

RE: Request for Updated Information and Data for the 2011 Long-Term Reliability Assessment (LTRA)

On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR—previously referred to as Clean Air Transport Rule or CATR), requiring significant reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions that cross state boundaries. Emission reductions will take effect quickly, starting January 1, 2012 for SO_2 and annual NO_X reductions, and May 1, 2012 for ozone-season NO_X reductions.

In a recent risk assessment completed by the NERC Planning Committee, finalized environmental regulations as well future proposed rules, such as the Air Toxics Rule (previously referred to as MACT) which places strict emission limits on a unit-specific basis, was the number one risk to bulk power system reliability over the next one to five years. The short-term reliability risks are primarily due to the short timelines associated with each of these two rules (2012 for CSAPR; 2015 for Air Toxics). While NERC has previously studied this issue, uncertainties in proposed EPA rules continue to affect industry decisions on potential retirements and retrofit efforts. For example, in the wake of the newly finalized CSAPR, previously unknown requirements may affect grid reliability of certain parts of the U.S. unless additional resources or operational procedures are put in place. For example, the proposed rule did not include Texas as a state that would need to comply with this rule.[365] These uncertainties continue to stress the coordinated planning functions, and affects resource availability, transmission plans and planning Reserve Margins.

Consistent with the objective to provide the most valuable, accurate and comprehensive reliability assessment, NERC is requesting updated information and data to support the *2011 Long-Term Reliability Assessment*. This request is an invitation to provide updated data and information due to changes observed in the previously submitted reference case.

It is NERC's intention to provide accurate projections of supply available to meet Reserve Margin requirements as well as a comprehensive assessment of the bulk power system preparations industry is making to support reliability, documenting them in the *2011 Long-Term Reliability Assessment*. The comprehensive assessment will leverage existing analyses performed by multiple Planning Authorities in both the Eastern and Texas Interconnections and focus on reliability issues. Lack of flexibility, loss of units due to early retirement, blackstart capability, and coordination

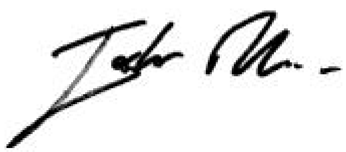
[365] http://www.ercot.com/news/press_releases/show/354.

required to accommodate scheduled outages for retrofits all contribute to significant reliability considerations as the convergence of multiple environmental rules are implemented.

Regional Entity staff must coordinate with their stakeholders and submit updated information both in the form of quantitative data (*i.e.,* updates to the ERO-2011LTRA Data Form) as well as qualitative narratives, where applicable. These updates can be included as revisions to the existing assessment, or as a separate narrative that may be included in the NERC summary Reliability Assessment section. **Updates to the *2011 Long-Term Reliability Assessment* are due back to NERC no later than September 9, 2011. Responses should be submitted directly to the NERC Reliability Assessment staff (assessments@nerc.net).** During the normal review and comment period (September and October), the Reliability Assessment Subcommittee, the Planning Committee, and the Board of Trustees will have opportunities to provide input.

On behalf of NERC Staff, we appreciate the timely efforts performed by the industry to address these issues and develop solutions that will maintain bulk power system reliability. Please contact me with any questions you may have concerning this request.

Sincerely,



John N. Moura
Manager, Reliability Assessment
North American Electric Reliability Corporation

Appendix III: Reliability Concepts Used in this Report

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:[366]

- **Adequacy** — is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** — is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand — demand that the end-use customer makes available to its LSE via contract or agreement for curtailment.[367]
- 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.

[366] Additional information regarding the Adequate Level of Reliability (ALR): http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[367] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

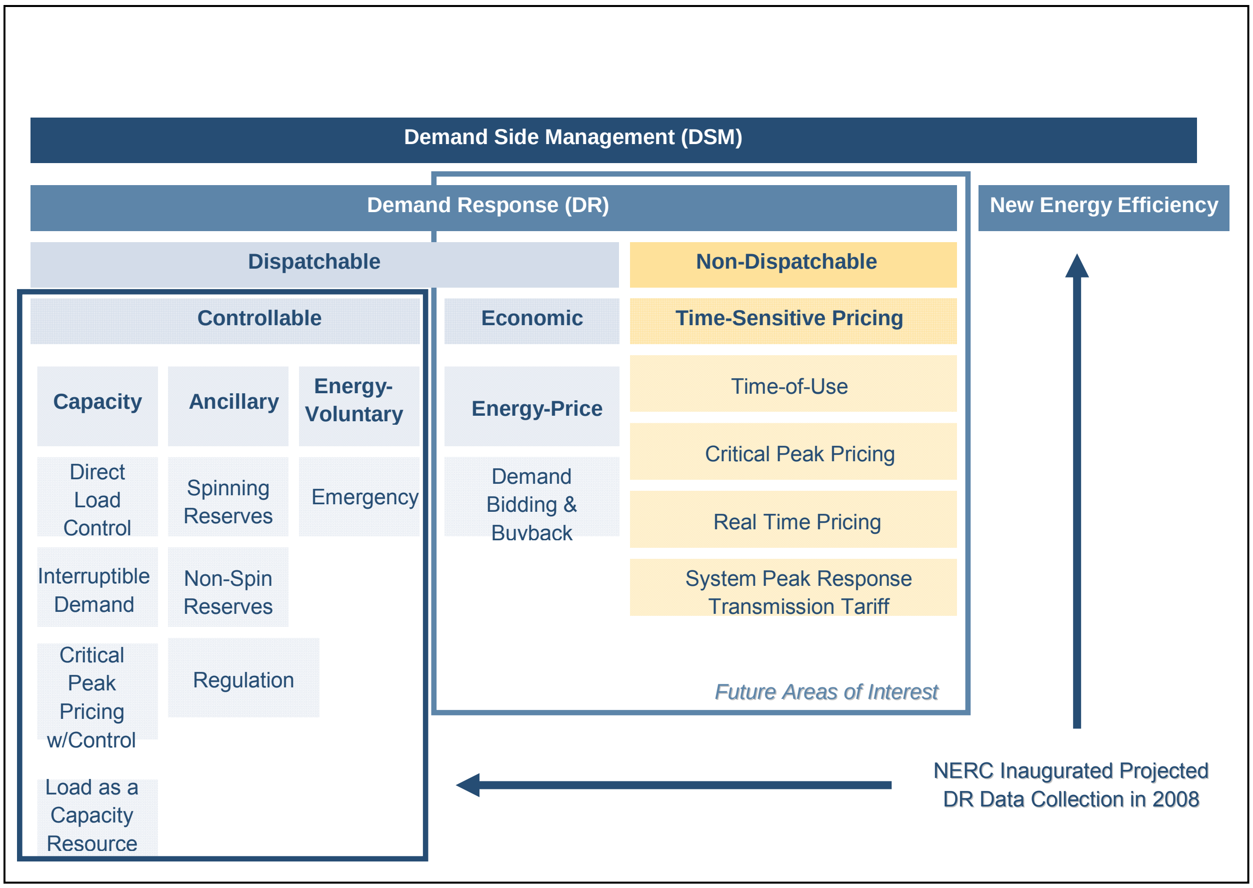
Demand Response Concepts and Categorization

As the industry's use of Demand Side Management (DSM) evolves, NERC's data collection and reliability assessments need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected Energy Efficiency programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect Demand Response programs such as Conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use

Note the context of these activities and programs is DSM, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. The Demand Response categories defined in *Terms Used in this Report* (Table IV).

Table IV: NERC Data Collection and Categorization for Demand-Side Management



Appendix IV: Terms Used in this Report

Ancillary (Controllable Demand Response) — Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Anticipated Capacity Resources – *Existing-Certain* and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports.

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

Capacity (Controllable Demand Response**) —** Demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Categories — *See* ***Existing Generation Resources, Future Generation Resources,*** *and* ***Conceptual Generation Resources***.

Capacity Margin (%) — *See* ***Deliverable Capacity Margin (%)*** *and* ***Prospective Capacity Margin (%)***. Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with *Reserve Margin(s) (%)* for NERC Assessments.

***Conceptual* Generation Resources** — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Conservation – *See* ***Energy Conservation***

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response**)** — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — *See* ***Contractually Interruptible***

Demand – *See* ***Net Internal Demand, Total Internal Demand***

Demand Bidding & Buyback (Controllable Energy-Price Demand Response**) —** Demand-side resource that enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

Demand Response — Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.[368]

Dispatchable (Demand Response**)** — Demand-side resource curtails according to instruction from a control center.

[368] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 www.nerc.com/files/Glossary_2009April20.pdf

Disturbance Classification Scale — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Disturbance Event – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Economic (Controllable Demand Response**) —** Demand-side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) **—** Demand-side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

Energy Efficiency — Permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP—002-0:

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

Energy Only (Capacity) — Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Energy-Price (Controllable Economic Demand Response**) —** Demand-side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

Existing-Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[369] that is eligible to bid into a market or has been designated as a firm network resource.
3. Network Resource[370], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
4. Energy-only resources[371] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[372]
5. Capacity resources that cannot be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[373] during the period of analysis in the assessment.

Existing-Certain **& Net Firm Transactions** – *Existing-Certain* capacity resources plus Firm Imports, minus Firm Exports. (MW)

Existing-Certain **and Net Firm Transactions (%)** (Margin Category) – *Existing-Certain* & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources — *See* *Existing-Certain*, *Existing-Other*, *Existing, but Inoperable.*

Existing-Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load

[369] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[370] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[371] Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.

[372] Energy only resources with transmission service constraints are to be considered in category *Existing-Other*.

[373] Energy only resources with transmission service constraints are to be considered in category *Existing-Other*.

during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories *Existing-Certain* or *Existing-Other*, but is not limited to, the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other existing but out-of-service generation (that cannot be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecasted to return to service.

Existing-Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in *Existing-Certain*. This category includes, but is not limited to the following:

- A resource with non-firm or other similar transmission arrangements.
- Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
- Mothballed generation (that may be returned to service for the period of the assessment).
- Portions of variable generation not counted in the *Existing-Certain* category (*e.g.,* wind, solar, etc. that may not be available or derated during the assessment period).
- Hydro generation not counted as *Existing-Certain* or derated.
- Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Expected implies that a contract has not been executed, but in negotiation, projected or other. These Purchases or Sales are expected to be firm.
2. Expected Purchases and Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Firm implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also* ***Future, Planned*** *and* ***Future, Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.

2. Regulatory permits being approved, any one of the following:
    a. Site permit
    b. Construction permit
    c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future, Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future, Planned* and are not included in the *Conceptual* category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

1. Be curtailed or interrupted at any time for any reason.
2. Energy-only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the *Future, Planned* category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in category *Future, Planned* or derated.
5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future, Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or firm) or other similar resource.
2. Where organized markets exist, designated market resource[374] that is eligible to bid into a market or has been designated as a firm network resource.
3. Network Resource[375], as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[376]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

Load as a Capacity Resource (Controllable Capacity Demand Response) — Demand-side resources that commit to pre-specified load reductions when system contingencies arise.[377]

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[374] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[375] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[376] Energy only resources with transmission service constraints are to be considered in category Future, Other.

NERC's Bulk Power System Disturbance Classification Scale[378] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staff to determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's Bulk Power System Event Classification Scale is designed to classify bulk power system disturbances by severity, size, and impact to the general public.

Operating Security Events — Operating reliability events are those that significantly affect the integrity of interconnected system operations. They are divided into 5 categories to take into account their different system impact.

- **Category 1:** An event results in any or combination of the following actions:
  a. The loss of a bulk power transmission component beyond recognized criteria,*i.e.,* single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
  b. Frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.
  c. Frequency above the High FTL more than 5 minutes.
  d. Partial loss of dc converter station (mono-polar operation).
  e. "Clear-Sky" Inter-area oscillations.
  f. Intended and controlled system separation by proper Special Protection Schemes / Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
  g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
  h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.
- **Category 2**: An event results in any or combination of the following actions:
  a. Complete loss of dc converter station.
  b. The loss of multiple bulk power transmission components.
  c. The loss of an entire switching station (all lines, 100 kV or above).
  d. The loss of an entire generation station of 5 or more generators (aggregate stations of 75 MW or higher).
  e. Loss of off-site power (LOOP) to a nuclear generating station.
  f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.

Continued Footnote:

[377] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning Reserve Margins.

[378] http://www.nerc.com/page.php?cid=5%7C252.

h. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the Texas or Québec Interconnections).
i. The planned automatic rejection of generation through special protection schemes (SPS) or remedial action schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.
k. SPS/RAS misoperation.

- **Category 3:** An event results in any or combination of the following actions:
  a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
  c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.
- **Category 4:** An event results in any or combination of the following actions:
  a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.
- **Category 5:** An event results in any or combination of the following actions:
  a. The loss of load of 10,000 MW or more.
  b. The loss of generation of 10,000 MW or more.

Resource Adequacy Events — Adequacy events are divided into three categories based on Standard EOP—002-0 (Capacity and Energy Emergencies).

- **Category A1**: No disturbance events and all available resources in use.
  a. Required Operating Reserves cannot 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 per contracts.
  d. Demand-side management.
  e. Utility load Conservation measures.
- **Category A3**: Firm load interruption imminent or in progress.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*i.e.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-dispatchable (Demand Response**) —** Demand-side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Non-Firm implies a non-firm contract has been signed.
2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity**) —** The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Prospective Capacity Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Prospective Capacity Resources. Replaced in 2009 with *Prospective Capacity Reserve Margin (%)* for NERC Assessments.

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

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

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally firm.

2. Provisional Purchases and Sales should be considered in the reliability assessments.

Purchases/Imports Contracts – *See* ***Transaction Categories***

Real-time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Reserve Margin Level – *See* ***NERC Reference Reserve Margin Level***

Regulation (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[379] The government of Canada has a similar definition.[380] Variable generation is a subset of Renewable Energy—See ***Variable Generation***.

Renewables — *See* ***Renewable Energy***

Reserve Margin (%) — *See* ***Deliverable Capacity Reserve Margin (%)*** *and* ***Prospective Capacity Reserve Margin (%)***. Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Resource Adequacy Events — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Sales/Exports Contracts – *See* ***Transaction Categories***

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response) Rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

[379] http://www1.eere.energy.gov/site_administration/ glossary.html#R.

[380] http://www.cleanenergy.gc.ca/faq/ index_e.asp#whatiscleanenergy.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

Total Internal Demand: The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real-time Pricing and System Peak Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response**) —** Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods.

Transaction Categories (*See also* ***Firm, Non-Firm, Expected*** *and* ***Provisional)*** **—** Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region.
Example: If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Loading Relief (TLR) Levels — Various levels of the TLR Procedure from Reliability Standard IRO—006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations

- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

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

- Under Construction
- Construction of the line has begun

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

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[381] Variable generation sources which include wind, solar, ocean and some hydro generation resources are all renewable based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the bulk power system planning and operations: variability and uncertainty.

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

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

Appendix V: Abbreviations Used in this Report

A/C	Air Conditioning
AEP	American Electric Power
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
BA	Balancing Authorities
BASN	Basin (subregion of WECC)
BCF	Billion cubic feet
BCFD	Billion cubic feet per day
CALN	California-North (subregion of WECC)
CALS	California-South (subregion of WECC)
CANW	WECC-Canada (subregion of WECC)
CFL	Compact Fluorescent Light
CMPA	California-Mexico Power Area
COI	California-Oregon Intertie
COS	Coordinated Outage (transmission) System
CPUC	California Public Utilities Commission
CRO	Contingency Reserve Obligation
CRPP	Comprehensive Reliability Planning Process (of NYISO)
DADRP	Day-Ahead Demand Response Program
dc	Direct Current
DCLM	Direct Controlled Load Management
DFW	Dallas/Fort Worth
DLC	Direct Load Control
DOE	U.S. Department of Energy
DSG	Dynamics Study Group
DSI	Direct-served Industry
DSM	Demand-Side Management
DSW	Desert Southwest (subregion of WECC)
DVAR	D-VAR® reactive power compensation system
EDRP	Emergency Demand Response Program
EE	Energy Efficiency
EEA	Energy Emergency Alert
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Agency (of DOE)
EILS	Emergency Interruptible Load Service (of ERCOT)
EISA	Energy Independence and Security Act of 2007 (USA)
ELCC	Effective Load-carrying Capability
EMTP	Electromagnetic Transient Program
ENS	Energy Not Served

EOP	Emergency Operating Procedure
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FCITC	First Contingency Incremental Transfer Capability
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
FP	*Future-Planned*
FO	*Future-Other*
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GGGS	Gerald Gentleman Station Stability
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool (of MAPP)
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
HVac	Heating, Ventilating, and Air Conditioning
IA	Interchange Authority
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (in Ontario)
IOU	Investor Owned Utility
IPL/NRI	International Power Line/Northeast Reliability Interconnect Project
IPSI	Integrated Power System Plan
IRM	Installed Reserve Margin
IROL	Interconnection Reliability Operating Limit
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LaaRs	Loads acting as a Resource
LCR	Locational Installed Capacity Requirements
LDC	Load Duration Curve
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss Of Load Probability
LOOP	Loss of off-site power
LRP	Long Range Plan
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
LTSG	Long-term Study Group
MAAC	Mid-Atlantic Area Council

Maf	Million acre-feet
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCRSG	Midwest Contingency Reserve Sharing Group
MEXW	WECC-Mexico (subregion of WECC)
MISO	Midwest Independent Transmission System Operator
MPRP	Maine Power Reliability Program
MRO	Midwest Reliability Organization
MVA	Megavolt amperes
MVAr	Mega-VArs
MW	Megawatts (millions of watts)
MWEX	Minnesota Wisconsin Export
NB	New Brunswick
NBSO	New Brunswick System Operator
NDEX	North Dakota Export Stability Interface
NEEWS	New England East West Solution
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NOPSG	Northwest Operation and Planning Study Group
NORW	Northwest (subregion of WECC)
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NSPI	Nova Scotia Power Inc.
NTSG	Near-term Study Group
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
NYPA	New York Planning Authority
NYRSC	New York State Reliability Council, LLC
NYSERDA	New York State Energy and Research Development Agency
OASIS	Open Access Same Time Information Service
OATT	Open Access Transmission Tariff
OP	Operating Procedure
OPA	Ontario Power Authority
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
OTC	Operating Transfer Capability
OVEC	Ohio Valley Electric Corporation
PA	Planning Authority
PACE	PacifiCorp East
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PCAP	Pre-Contingency Action Plans
PCC	Planning Coordination Committee (of WECC)
PJM	PJM Interconnection

PRB	Powder River Basin
PRC	Public Regulation Commission
PRSG	Planned Reserve Sharing Group
PSA	Power Supply Assessment
PUCN	Public Utilities Commission of Nevada
QSE	Qualified Scheduling Entities
RA	Resource Adequacy
RAP	Remedial Action Plan
RAR	Resource Adequacy Requirement
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RGGI	Regional Greenhouse Gas Initiative
RIS	Resource Issues Subcommittee of NERC Planning Committee
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
ROCK	Rockies (subregion of WECC)
RP	Reliability Planner
RPM	Reliability Pricing Mode
RRS	Reliability Review Subcommittee
RSG	Reserve Sharing Group
RTEP	Regional Transmission Expansion Plan (for PJM)
RTO	Regional Transmission Organization
RTP	Real-time Pricing
RTWG	Renewable Technologies Working Group
SA	Security Analysis
SasKPower	Saskatchewan Power Corp.
SCADA	Supervisory Control and Data Acquisition
SCC	Seasonal Claimed Capability
SCD	Security Constrained Dispatch
SCDWG	Short Circuit Database Working Group
SCEC	State Capacity Emergency Coordinator (of FRCC)
SCR	Special Case Resources
SEMA	Southeastern Massachusetts
SEPA	State Environmental Protection Administration
SERC	SERC Reliability Corporation
SMUD	Sacramento Municipal Utility District
SOL	System Operating Limits
SPP	Southwest Power Pool
SPS	Special Protection System
SPS/RAS	Special Protection Schemes / Remedial Action Schemes
SRIS	System Reliability Impact Studies
SRWG	System Review Working Group

STATCOM	Static Synchronous Compensator
STEP	SPP Transmission Expansion Plan
SVC	Static VAr Compensation
TCF	Trillion Cubic Feet
TFCP	Task Force on Coordination of Planning
THI	Temperature Humidity Index
TIC	Total Import Capability
TID	Total Internal Demand
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPL	Transmission Planning
TRE	Texas Regional Entity
TRM	Transmission Reliability Margins
TS	Transformer Station
TSP	Transmission Service Provider
TSS	Technical Studies Subcommittee
TVA	Tennessee Valley Authority
USBRLC	United States Bureau of Reclamation Lower Colorado Region
UFLS	Under Frequency Load Shedding Schemes
UVLS	Under Voltage Load-Shedding
VAr	Voltampere reactive
VACAR	Virginia and Carolinas (subregion of SERC)
VSAT	Voltage Stability Assessment Tool
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index
WUMS	Wisconsin-Upper Michigan Systems

Appendix VI: NERC-Wide Transmission Additions, Upgrades, and Retirements

Table Notes

Note 1: Included transmission projects are categorized as follows:

- Planned or Under Construction.
- In-service (or retirement) dates between 2011 and 2021
- Operating voltage over 200 kV

Note 2: The following considerations should be applied to the transmission line lengths:

- Presented in terms of net change in circuit miles
- Relining, rerating, and other upgrades typically result in no change in line length
- Negative line lengths represent retirements (unless otherwise noted)

Note 3: A comprehensive list, including detailed information about each project, will be published in the 2011 NERC Electricity Supply and Demand (ES&D) Database.[382]

[382] NERC ES&D Website: http://www.nerc.com/page.php?cid=4%7C38.

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
ERCOT	Planned	West Shackelford	Sam Switch/Navarro	402.0	300-399	AC	-	2013
ERCOT	Planned	Krum West	Riley (Oklaunion)	322.8	300-399	AC	-	2013
ERCOT	Planned	Big Hill	Kendall	274.0	300-399	AC	-	2013
ERCOT	Planned	Willow Creek	Clear Crossing	220.0	300-399	AC	-	2013
ERCOT	Planned	Gray	Tesla	218.0	300-399	AC	-	2013
ERCOT	Planned	Scurry County	West Shackelford	204.0	300-399	AC	-	2013
ERCOT	Planned	Dermott	Willow Creek	189.0	300-399	AC	-	2013
ERCOT	Planned	Silverton	Tesla	170.0	300-399	AC	-	2013
ERCOT	Planned	Edith Clarke	West Shackelford	150.6	300-399	AC	-	2013
ERCOT	Planned	Cottonwood	Edith Clarke	149.0	300-399	AC	-	2013
ERCOT	Planned	Anna Switch	Krum W.	140.0	300-399	AC	-	2013
ERCOT	Planned	Gray	Oklaunion	132.2	300-399	AC	-	2013
ERCOT	Planned	Brown	Killeen	126.5	300-399	AC	-	2012
ERCOT	Planned	Sol	Rio Bravo	122.4	300-399	AC	-	2016
ERCOT	Planned	Zenith	Fayetteville	120.0	300-399	AC	-	2014
ERCOT	Planned	McCamey C	McCamey D	112.0	300-399	AC	-	2013
ERCOT	Planned	Brown	Newton	98.6	300-399	AC	-	2012
ERCOT	Planned	Central Bluff	Brown	96.1	300-399	AC	-	2012
ERCOT	Planned	LS03 White Deer	Hereford	91.2	300-399	AC	-	2013
ERCOT	Planned	Bluff Creek	Brown	86.6	300-399	AC	-	2012
ERCOT	Planned	Riley	Edith Clarke	85.6	300-399	AC	-	2013
ERCOT	Planned	Bowman	Riley (Oklaunion)	85.2	300-399	AC	-	2011
ERCOT	Planned	Bell County East-TNP One	Bell County East Switching	82.6	300-399	AC	-	2011
ERCOT	Planned	Hicks Switch	Willow Creek	80.4	300-399	AC	-	2013
ERCOT	Planned	Gray	White Deer	80.0	300-399	AC	-	2013
ERCOT	Planned	Tesla	Edith Clarke	79.8	300-399	AC	-	2013
ERCOT	Planned	Sand Bluff	Long Draw	77.4	300-399	AC	-	2013
ERCOT	Planned	Sweetwater East	Central Bluff	71.6	300-399	AC	-	2011
ERCOT	Planned	Cottonwood	Dermott	71.5	300-399	AC	-	2012
ERCOT	Planned	LS05 Silverton	White Deer	68.2	300-399	AC	-	2013
ERCOT	Planned	Dermott Switch	Scurry County South	65.4	300-399	AC	-	2011
ERCOT	Planned	LS04 Silverton	Cottonwood	64.5	300-399	AC	-	2013
ERCOT	Under Construction	Tonkawa	Sweetwater East	63.4	300-399	AC	-	2011
ERCOT	Planned	Edith Clarke	West Shackelford	59.6	300-399	AC	-	2013
ERCOT	Planned	Grelton	Long Draw	55.4	300-399	AC	-	2013

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
ERCOT	Planned	Trinidad	Watermill	52.0	300-399	AC	-	2012
ERCOT	Planned	Long Draw	Scurry County	50.7	300-399	AC	-	2013
ERCOT	Planned	North McCamey	Odessa EHV	50.0	300-399	AC	-	2013
ERCOT	Planned	Grelton	Odessa	49.9	300-399	AC	-	2013
ERCOT	Planned	LS01 Silverton	Nazareth	46.0	300-399	AC	-	2013
ERCOT	Planned	Ranchito	South McAllen	38.0	300-399	AC	-	2017
ERCOT	Planned	Krum West Switch	NW Carrollton	37.2	300-399	AC	-	2011
ERCOT	Planned	Sand Bluff 345 kV Station	Sand Bluff to Divide 345 kV line	37.0	300-399	AC	-	2013
ERCOT	Planned	Loma Alta	Rio Hondo	35.0	300-399	AC	-	2018
ERCOT	Planned	Twin Buttes	Big Hill	31.0	300-399	AC	-	2012
ERCOT	Under Construction	Scurry County South	Tonkawa	30.4	300-399	AC	-	2011
ERCOT	Planned	Lobo	Rio Bravo	30.0	300-399	AC	-	2015
ERCOT	Planned	Bearkat	Sand Bluff	28.9	300-399	AC	-	2013
ERCOT	Planned	Newton	Killeen	27.9	300-399	AC	-	2012
ERCOT	Planned	DeCordova	Benbrook	27.0	300-399	AC	-	2018
ERCOT	Planned	LS02 Nazareth	Hereford	25.5	300-399	AC	-	2013
ERCOT	Planned	Loma Alta	la Palma	25.0	300-399	AC	-	2018
ERCOT	Planned	Southeast Nacogdoches	Lufkin Switch	21.0	300-399	AC	-	2022
ERCOT	Planned	Cagnon	Hill Country	19.5	300-399	AC	-	2020
ERCOT	Planned	Collin Switch	NW. Carrollton	19.3	300-399	AC	-	2016
ERCOT	Planned	Central Bluff -	Bluff Creek	19.0	300-399	AC	-	2011
ERCOT	Planned	Fayette Power Project	Fayette Power Project	16.4	300-399	AC	-	2015
ERCOT	Planned	Temple Switch	Salado	15.2	300-399	AC	-	2011
ERCOT	Planned	North McCamey	Bakersfield	15.0	300-399	AC	-	2013
ERCOT	Planned	N. Edinburg	Sol	15.0	300-399	AC	-	2016
ERCOT	Planned	Nopalito	Sand Dollar	14.5	300-399	AC	-	2015
ERCOT	Planned	Liggett	Trinity Switch	12.8	300-399	AC	-	2018
ERCOT	Planned	Frontera	Sol	12.4	300-399	AC	-	2016
ERCOT	Planned	Frontera	South McAllen	12.2	300-399	AC	-	2016
ERCOT	Planned	Lon Hill	Sand Dollar	11.5	300-399	AC	-	2014
ERCOT	Planned	Venus	Webb	11.3	300-399	AC	-	2014
ERCOT	Planned	Hill Country	Skyline	11.0	300-399	AC	-	2020
ERCOT	Planned	Zenith	Gertie	10.0	300-399	AC	-	2012
ERCOT	Planned	LaPalma	Ranchito	10.0	300-399	AC	-	2018
ERCOT	Planned	Tricorner	Seagoville	9.4	300-399	AC	-	2014
ERCOT	Planned	Gilleland	Techridge	8.0	300-399	AC	-	2015

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
ERCOT	Planned	Riley	Oklaunion	3.6	300-399	AC	-	2013
ERCOT	Planned	Martin Lake - Trinidad	Mount Enterprise	2.0	300-399	AC	-	2014
ERCOT	Planned	Sand Dollar	Las Brisas Energy Center	2.0	300-399	AC	-	2014
ERCOT	Planned	Sand Dollar	Las Brisas	2.0	300-399	AC	-	2016
ERCOT	Planned	Rattlesnake Road	Lake Creek	1.5	300-399	AC	-	2011
ERCOT	Planned	Singleton	T.H. Wharton	1.0	300-399	AC	-	2011
ERCOT	Planned	Twin Buttes	Brown	0.2	300-399	AC	-	2012
ERCOT	Planned	Lon Hill	Whitepoint	0.1	300-399	AC	-	2014
ERCOT	Planned	Whitepoint	Hairpin into Nopalito	0.1	300-399	AC	-	2014
FRCC	Planned	Manatee	Bob White	30.0	200-299	AC	1,190	2015
FRCC	Planned	St. Johns	Pringle	25.0	200-299	AC	759	2016
FRCC	Planned	Hines Energy Complex	West Lake Wales #2	21.0	200-299	AC	1,000	2011
FRCC	Planned	Kathleen	Zephyrhills N	11.0	200-299	AC	1,000	2012
FRCC	Planned	Intercession City	Gifford	13.0	200-299	AC	1,370	2013
FRCC	Planned	Disston	Northeast	4.0	200-299	AC	1,000	2013
FRCC	Planned	Disston	40th Street	4.0	200-299	AC	1,000	2014
FRCC	Planned	Greenland Energy Center	Nocatee	4.4	200-299	AC	668	2015
FRCC	Planned	Hopkins-Crawfordville 230 Tap	Sub 5 230	8.0	200-299	AC	458	2012
FRCC	Planned	Polk	Pebbledale (2)	-	200-299	AC	1,119	2019
FRCC	Planned	Polk	Pebbledale (1)	-	200-299	AC	729	2019
FRCC	Planned	Polk	FishHawk	30.5	200-299	AC	1,119	2019
FRCC	Planned	Big Bend	State Road 60	13.8	200-299	AC	729	2011
FRCC	Planned	Sanford	Magnolia	7.0	200-299	AC	588	2013
FRCC	Planned	Volusia	Magnolia	7.0	200-299	AC	588	2013
FRCC	Planned	St johns	Pellicer	8.0	200-299	AC	759	2015
FRCC	Planned	O'Neil	Kingsland	7.5	200-299	AC	759	2012
FRCC	Planned	Alico	Ft Myers	19.5	200-299	AC	759	2014
FRCC	Planned	Alico	Ft Myers	1.0	200-299	AC	759	2014
FRCC	Planned	Turkey Pt	Prince230	11.0	200-299	AC	759	2012
FRCC	Under Construction	CENTR PK	GEC	11.3	200-299	AC	668	2011
FRCC	Planned	DINSMORE	SJRPP	14.0	200-299	AC	668	2016
FRCC	Planned	DINSMORE	WESTLAKE	8.3	200-299	AC	668	2016
FRCC	Planned	NOCATEE	GEC	4.4	200-299	AC	668	2014
FRCC	Planned	FOREST	PT. MEAD	3.0	200-299	AC	668	2017
FRCC	Planned	PT. MEAD	SE JAX	3.1	200-299	AC	637	2017
FRCC	Under Construction	SJRPP	ROBNWOOD	15.2	200-299	AC	668	2011

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
FRCC	Planned	CR PLANT	Lecanto	13.7	200-299	AC	677	2012
FRCC	Planned	BROOKRIDGE 230.00	BROOKSVL W 230.00	3.3	200-299	AC	677	2015
FRCC	Planned	BROOKSVL W 230.00	HUDSON 230.00	11.9	200-299	AC	677	2015
FRCC	Planned	WHEELER	THONOTOSASSA	8.2	200-299	AC	1,118	2015
FRCC	Planned	PEBB	WILLOW	11.0	200-299	AC	1,118	2018
FRCC	Planned	WILLOW	WHEELER	20.0	200-299	AC	1,118	2018
FRCC	Planned	Davis Rd	Dlmbry	13.0	200-299	AC	1,118	2019
MISO	Planned	Lyon County	Cedar Mountain	51.9	300-399	AC	2,066	2013
MISO	Planned	Cedar Mountain	Helena	62.2	300-399	AC	2,066	2013
MISO	Planned	Cedar Mountain	Helena	62.2	300-399	AC	2,066	2013
MISO	Planned	Helena	Lake Marion	26.6	300-399	AC	2,066	2014
MISO	Planned	Lake Marion	Hampton Corner	18.5	300-399	AC	2,066	2014
MISO	Planned	Lyon County	Hazel	23.5	300-399	AC	2,066	2015
MISO	Planned	Hazel	Minnesota Valley	6.0	200-299	AC	1,558	2015
MISO	Under Construction	AB Brown	Reid (BREC)	25.7	300-399	AC	1,430	2012
MISO	Planned	Salem	Hazleton	81.0	300-399	AC	1,195	2012
MISO	Planned	Big Stone South	Ellendale	145.0	300-399	AC	-	2019
MISO	Planned	Big Stone South	Brookings 345 kV double circuit	65.0	300-399	AC	-	2017
MISO	Planned	Big Stone	Big Stone South	2.0	200-299	AC	-	2017
MISO	Planned	Big Stone	Big Stone South	2.0	200-299	AC	-	2017
MISO	Planned	Beaver	Davis Besse	-	300-399	AC	-	2014
MISO	Planned	Fargo	Maple Ridge	20.0	300-399	AC	1,793	2016
MISO	Planned	Boswell	Essar Mine Sub (Calumet)	16.0	200-299	AC	423	2012
MISO	Planned	Essar steel plant sub	Shannon	8.0	200-299	AC	423	2015
MISO	Planned	Blackberry	Essar Mine Sub (Calumet)	16.0	200-299	AC	465	2012
MISO	Planned	Essar Mine Sub (Calumet)	Essar steel plant sub	2.5	200-299	AC	465	2012
MISO	Planned	Noblesville Gen. Station	Geist	0.6	200-299	AC	319	2011
MISO	Planned	North Madison	Cardinal	20.5	300-399	AC	2,110	2018
MISO	Planned	Rapson (formerly Wyatt)	Baker (formerly Reese)	56.0	300-399	AC	-	2013
MISO	Planned	Rapson (formerly Wyatt)	Baker (formerly Reese)	56.0	300-399	AC	-	2013
MISO	Planned	Rapson (formerly Wyatt)	Greenwood	65.0	300-399	AC	-	2015
MISO	Planned	Rapson (formerly Wyatt)	Greenwood	65.0	300-399	AC	-	2015
MISO	Planned	Greenwood	Fitz (formerly Saratoga)	19.0	300-399	AC	-	2015
MISO	Planned	Greenwood	Fitz (formerly Saratoga)	19.0	300-399	AC	-	2015
MISO	Planned	Ellendale	G359 POI	24.0	200-299	AC	380	2011
MRO-Manitoba	Planned	Wuskwatim S.S.	Herblet Lake	85.2	200-299	AC	565	2011

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
MRO-Manitoba	Planned	Wuskwatim G.S.	Wuskwatim S.S.	0.7	200-299	AC	565	2011
MRO-Manitoba	Planned	Wuskwatim G.S.	Wuskwatim S.S.	0.7	200-299	AC	565	2011
MRO-Manitoba	Planned	Wuskwatim G.S.	Wuskwatim S.S.	0.7	200-299	AC	565	2011
MRO-Manitoba	Planned	Herblet Lake	Rall's Island	102.5	200-299	AC	565	2011
MRO-Manitoba	Planned	D54C tap	Neepawa 230/66 station	1.0	200-299	AC	565	2013
MRO-Manitoba	Planned	R32V tap	Transcona	1.0	200-299	AC	658	2012
MRO-Manitoba	Planned	R33V tap	Transcona	1.0	200-299	AC	658	2012
MRO-Manitoba	Planned	Henday	Conawapa Constr Power	18.2	200-299	AC	769	2017
MRO-Manitoba	Planned	LaVerendrye	St Vital	21.1	200-299	AC	658	2015
MRO-Manitoba	Planned	Dorsey	Portage	43.5	200-299	AC	565	2014
MRO-Manitoba	Planned	Keewatinoow	Riel	833.3	400-599	DC	2,000	2017
MRO-Manitoba	Planned	Keewatinoow	Henday	18.2	200-299	AC	769	2017
MRO-Manitoba	Planned	Keewatinoow	Henday	18.2	200-299	AC	769	2017
MRO-Manitoba	Planned	Keewatinoow	Henday	18.2	200-299	AC	769	2017
MRO-Manitoba	Planned	Conawapa	Long Spruce	34.7	200-299	AC	1,029	2017
MRO-Manitoba	Planned	Dorsey	Riel	30.9	400-599	AC	3,746	2019
MRO-Manitoba	Planned	St Joseph Wind	Letellier	4.8	200-299	AC	515	2011
MRO-Manitoba	Planned	Wuskwatim S.S.	Herblet Lake	85.2	200-299	AC	565	2011
MRO-MAPP	Planned	Center 345 KV Substation	Prairie 345 KV Substation	250.0	300-399	AC	1,206	2013
MRO-MAPP	Planned	Wilton 230 KV Substation	Cass Lake 230 KV Substation	19.0	200-299	AC	641	2012
MRO-MAPP	Planned	Cass Lakev230 KV Substation	Boswell 230 KV Substation	51.0	200-299	AC	641	2012
MRO-MAPP	Planned	Lower Brule dbl ckt	Big Bend	2.1	200-299	AC	472	2014
MRO-MAPP	Under Construction	Williston 2 (WN2)	Tioga (TGA)	61.0	200-299	AC	200	2011
MRO-MAPP	Planned	Brookings, SD	Twin Cities, MN	230.0	300-399	AC	1,000	2015
MRO-SaskPower	Planned	Peebles Switching Station	Tantallon Switching Station	84.0	200-299	AC	765	2015
MRO-SaskPower	Planned	Aberdeen Switching Station	Wolverine Switching Station	65.0	200-299	AC	765	2013
NPCC-New England	Planned	Carver	Bourne	17.9	300-399	AC	2,169	2014
NPCC-New England	Planned	West Farnum S/S	CT/RI Border	17.7	300-399	AC	2,172	2013
NPCC-New England	Planned	Millbury S/S	West Farnum S/S	20.7	300-399	AC	2,172	2013
NPCC-New England	Planned	Kent County	West Farnum S/S	0.1	300-399	AC	1,353	2011
NPCC-New England	Under Construction	Berry St	303 Taps	21.4	300-399	AC	1,545	2012
NPCC-New England	Planned	Card S/S	Lake Road S/S	29.3	300-399	AC	2,420	2015
NPCC-New England	Planned	Lake Road S/S	CT/RI Border	7.6	300-399	AC	2,420	2015
NPCC-New England	Planned	Frost Bridge S/S	North Bloomfield S/S	35.4	300-399	AC	2,420	2016
NPCC-New England	Planned	Manchester	Meekville Jct.	2.0	300-399	AC	2,420	2013
NPCC-New England	Planned	North Bloomfield S/S	CT/MA Border	11.9	300-399	AC	2,420	2013

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
NPCC-New England	Under Construction	Agawam S/S	Ludlow S/S	16.8	300-399	AC	2,420	2013
NPCC-New England	Under Construction	Orrington S/S	Albion Road S/S	59.0	300-399	AC	2,151	2012
NPCC-New England	Under Construction	Albion Road S/S	Coopers Mills S/S	21.0	300-399	AC	2,151	2014
NPCC-New England	Under Construction	Larrabee Road S/S	Coopers Mills S/S	34.3	300-399	AC	2,151	2013
NPCC-New England	Under Construction	Larrabee Road S/S	Surowiec S/S	17.0	300-399	AC	2,151	2012
NPCC-New England	Under Construction	Surowiec S/S	Raven Farm S/S	12.4	300-399	AC	2,151	2012
NPCC-New England	Planned	Maguire Road S/S	South Gorham S/S	21.0	300-399	AC	2,151	2012
NPCC-New England	Planned	Maguire Road S/S	Three Rivers Switchyard	19.2	300-399	AC	2,151	2013
NPCC-New England	Planned	Scobie S/S	PSNH/NGRID Border	10.8	300-399	AC	2,420	2015
NPCC-Ontario	Under Construction	Ingersoll TS	Kam TS	15.0	200-299	AC	964	2012
NPCC-Ontario	Under Construction	Allanburg TS	Middleport TS	93.0	200-299	AC	964	-
NPCC-Ontario	Under Construction	Bruce Complex	Milton TS	110.0	400-599	AC	5,656	2012
NPCC-Québec	Planned	New Richmond Wind Farm	New Richmond W.F.	5.6	200-299	AC	-	2012
NPCC-Québec	Planned	Lac-Alfred Wind Farm	Lac-Alfred W.F.	17.4	300-399	AC	-	2012
NPCC-Québec	Planned	Seigneurie-de-Beaupré I and II	Seigneurie-de-Beaupré W.F.	14.3	300-399	AC	-	2013
NPCC-Québec	Planned	St-Bruno-de-Montarville	St-Bruno-de-Montarville	0.6	300-399	AC	-	2013
NPCC-Québec	Planned	Rivière-du-Moulin Wind Farm	Rivière-du-Moulin	15.5	300-399	AC	-	2014
NPCC-Québec	Planned	Clermont Wind Farm	Clermont	6.2	300-399	AC	-	2015
NPCC-Québec	Planned	Anse-Pleureuse 230/25 kV T.S.	Anse-Pleureuse	0.1	200-299	AC	-	2012
NPCC-Québec	Planned	Lachenaie 315/25 kV T.S.	Lanaudière	-5	300-399	AC	-	2013
NPCC-Québec	Planned	Lachenaie 315/25 kV T.S.	Lachenaie	1	300-399	AC	-	2013
NPCC-Québec	Planned	Aux Outardes 735 kV	Aux Outardes 735 kV	3.1	600+	AC	-	2014
NPCC-Québec	Planned	Romaine River Generation	Romaine-2	162.8	300-399	AC	-	2014
NPCC-Québec	Planned	Romaine River Generation	Romaine-1	16.8	300-399	AC	-	2016
NPCC-Québec	Planned	Romaine River Generation	Romaine-4	109.4	300-399	AC	-	2017
NPCC-Québec	Planned	Romaine River Generation	Romaine-3	19.9	300-399	AC	-	2020
NPCC-Québec	Under Construction	Goemon	Gros-Morne	66.0	200-299	AC	749	2011
NPCC-Québec	Under Construction	La Sarcelle	Eastmain 1	63.4	300-399	AC	885	2011
NPCC-Québec	Under Construction	Eastmain 1-A	Eastmain 1	1.2	300-399	AC	2231	2011
NPCC-Québec	Under Construction	Des Moulins	Antoine-Lemieux Tap	1.9	200-299	AC	-	2012
NPCC-Québec	Under Construction	Limoilou	Limoilou Tap L2363-2364	0.5	200-299	AC	-	2011
NPCC-Québec	Under Construction	Le Plateau	Rimouski Tap	0.1	300-399	AC	-	2011
PJM	Under Construction	Orchard	Cumberland	15.0	200-299	AC	-	2012
PJM	Planned	Don Marquis	North Fork	-	300-399	AC	1,219	2014

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
PJM	Planned	North Fork	Bixby	-	300-399	AC	1,235	2014
PJM	Planned	Vassell	Kammer	-	600+	AC	4,257	2014
PJM	Planned	Vassell	Maliszewski	-	600+	AC	4,174	2014
PJM	Planned	Vassell	Hyatt	-	300-399	AC	1,409	2014
PJM	Planned	Vassell	Corridor	8.0	300-399	AC	1,409	2014
PJM	Under Construction	Maddox Creek	East Lima	-	300-399	AC	897	2011
PJM	Under Construction	Maddox Creek	Convoy	-	300-399	AC	897	2011
PJM	Planned	Monocacy	Catoctin	-	200-299	AC	-	2012
PJM	Planned	Ringgold	Catoctin	-	200-299	AC	-	2013
PJM	Planned	Carroll	Catoctin	-	200-299	AC	-	2013
PJM	Planned	Elko	Carbon Center Jct	6.0	200-299	AC	-	2014
PJM	Planned	Bear Run	Carbon Center Jct	4.0	200-299	AC	-	2014
PJM	Planned	Carbon Center	Carbon Center Jct	1.0	200-299	AC	-	2014
PJM	Planned	Bagley	Rapheal Road	6.0	200-299	AC	659	2015
PJM	Planned	Conastone	Graceton	8.6	200-299	AC	-	2014
PJM	Planned	Graceton	Bagley	13.8	200-299	AC	-	2014
PJM	Planned	Calvert Cliffs	Calvert Cliffs (new)	1.0	400-599	AC	-	2015
PJM	Planned	Speed	Paddy's West	16.7	300-399	AC	-	2012
PJM	Under Construction	Arsenal	Logans Ferry	12.0	300-399	AC	537	2012
PJM	Planned	Vienna	Steele	28.0	200-299	AC	551/551	2016
PJM	Planned	Mission	Indian River	6.6	200-299	AC	-	2015
PJM	Planned	Chestnut	Mission	40.4	600+	DC	-	2015
PJM	Planned	Chestnut	Gateway	14.4	600+	DC	-	2015
PJM	Planned	Chestnut	Gateway	1.0	600+	DC	-	2015
PJM	Planned	Chestnut	Mission	1.0	600+	DC	-	2015
PJM	Planned	Vienna	Loretto	-	200-299	AC	650/805	2015
PJM	Planned	Loretto	Piney Grove	-	200-299	AC	650/805	2015
PJM	Planned	Cranberry	Cabot	-	400-599	AC	2800/3600	2012
PJM	Planned	Cranberry	Wylie Ridge	-	400-599	AC	2800/3600	2012
PJM	Under Construction	Island Road	Penrose	0.1	200-299	AC	1,207	2011
PJM	Under Construction	Penrose	Grays Ferry	0.1	200-299	AC	1,207	2011
PJM	Planned	Bradford/Clay Tap	Clay	7.0	200-299	AC	166	2013
PJM	Planned	Colora/Clay Tap	Clay	-	200-299	AC	166	2013
PJM	Under Construction	Grays Ferry	Peltz	0.1	200-299	AC	1,088	2011
PJM	Under Construction	Grays Ferry/Penrose	Peltz	0.1	200-299	AC	1,207	2011
PJM	Under Construction	Whitpain	Center Point	-	400-599	AC	2,338	2011

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
PJM	Under Construction	Center Point	Elroy	-	400-599	AC	2,338	2011
PJM	Under Construction	Upper Providence/Perkiomen	Center Point	(0.1)	200-299	AC	1,245	2011
PJM	Under Construction	Center Point	North Wales	(0.1)	200-299	AC	1,245	2011
PJM	Planned	Keystone	Jacks Mountain	0.1	400-599	AC	-	2013
PJM	Planned	Jacks Mountain	Juniata	0.1	400-599	AC	-	2013
PJM	Planned	Conemaugh	Jacks Mountain	0.1	400-599	AC	-	2013
PJM	Planned	Possum Point	Burches Hill	32.3	400-599	AC	-	2015
PJM	Planned	Burches Hill	Chalk Point	19.4	400-599	AC	-	2015
PJM	Planned	Chalk Point	Chestnut	10.6	400-599	AC	-	2015
PJM	Planned	Chestnut	Gateway	42.7	600+	DC	-	2015
PJM	Planned	Chestnut	Mission	42.7	600+	DC	-	2015
PJM	Planned	Richie	Benning	2.0	200-299	AC	-	2012
PJM	Under Construction	Bear Garden	Bremo	1.0	200-299	AC	800	2011
PJM	Under Construction	Bremo	Bear Garden	1.0	200-299	AC	800	2011
PJM	Planned	Burke	Sideburn	2.0	200-299	AC	500	2014
PJM	Under Construction	Carson	Suffolk	50.0	400-599	AC	3,450	2011
PJM	Under Construction	Chickahominy	Lanexa	14.0	200-299	AC	722	2011
PJM	Under Construction	Chickahominy	Old Church	16.0	200-299	AC	797	2011
PJM	Planned	Chuckatuck	Newport News	15.0	200-299	AC	800	2012
PJM	Planned	Dooms	Lexington	39.0	400-599	AC	2,600	2012
PJM	Planned	Iron Bridge	Walmsley	3.0	200-299	AC	706	2011
PJM	Planned	Landstown	Virginia Beach	11.0	200-299	AC	800	2012
PJM	Under Construction	Meadowbrook	Loudoun	65.0	400-599	AC	3,500	2011
PJM	Planned	North Anna	Ladysmith	15.0	400-599	AC	3,500	2018
PJM	Planned	Remington	Sowego	11.0	200-299	AC	1,047	2012
PJM	Planned	Sowego	Gainesville	14.0	200-299	AC	1,047	2012
PJM	Under Construction	Suffolk	Fentress	26.0	200-299	AC	1,047	2011
PJM	Under Construction	Suffolk	Thrasher	10.0	200-299	AC	999	2011
PJM	Planned	Thelma	Carolina	10.0	200-299	AC	1,047	2011
PJM	Planned	Walmsley	Southwest	7.0	200-299	AC	706	2011
PJM	Planned	Yorktown	Hayes	8.0	200-299	AC	1,047	2012
PJM	Planned	Jenkins	Stanton	8.6	200-299	AC	653	2014
PJM	Planned	Brunner Island	West Shore	16.0	200-299	AC	653	2013
PJM	Planned	Susquehanna	Roseland	146.0	400-599	AC	-	2015
PJM	Under Construction	Hudson	South Waterfront	3.5	200-299	AC	514	2011
PJM	Planned	West Orange	Roseland	4.5	200-299	AC	-	2014

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
PJM	Planned	West Orange	Roseland	4.5	200-299	AC	-	2014
PJM	Planned	Roseland	Sewaren	29.8	200-299	AC	-	2014
PJM	Planned	Camden	Burlington	13.7	200-299	AC	-	2014
PJM	Planned	Camden	Cuthbert Blvd.	2.7	200-299	AC	-	2014
PJM	Planned	Gloucester	Cuthbert Blvd.	4.5	200-299	AC	-	2015
PJM	Planned	Gloucester	Camden	7.2	200-299	AC	-	2015
PJM	Planned	Athenia	Bergen	10.4	200-299	AC	-	2015
PJM	Planned	Montville	Jefferson	15.1	400-599	AC	3,005	2012
PJM	Planned	Jefferson	Bushkill	22.3	400-599	AC	3,005	2012
PJM	Planned	Roseland	Kearny	22.0	200-299	AC	-	2015
PJM	Planned	Buckingham	Pleasant	-	200-299	AC	-	2013
PJM	Planned	Athenia	Saddebrook	4.8	200-299	AC	-	2012
PJM	Planned	Kittanity	Newton	17.5	200-299	AC	-	2011
PJM	Planned	Somersville	Flagtown	4.0	200-299	AC	-	2012
PJM	Planned	Somersville	Bridgewater	3.0	200-299	AC	-	2012
PJM	Under Construction	South Mahwah	Waldwick J	5.5	200-299	AC	-	2011
PJM	Under Construction	South Mahwah	Waldwick K	5.5	200-299	AC	-	2011
PJM	Planned	Branchburg	Middlesex	13.2	200-299	AC	-	2011
PJM	Planned	Burlington	Croydon	0.3	200-299	AC	-	2015
PJM	Planned	Roseland	Kearny D-G	43.9	200-299	AC	-	2015
PJM	Planned	Hudson	S. waterfront	3.5	200-299	AC	-	2015
PJM	Planned	Mickelton	Gloucester	9.6	200-299	AC	-	2015
PJM	Planned	Camden	Richmond	1.8	200-299	AC	-	2015
PJM	Planned	W. Orange	Aldene	12.3	200-299	AC	-	2014
SERC-E	Planned	AM WIlliams	Cainhoy	9.0	200-299	AC	510	2017
SERC-E	Under Construction	Asheboro	Pleasant Garden	22.0	200-299	AC	1,195	2011
SERC-E	Planned	Canadys	St. George	8.0	200-299	AC	950	2018
SERC-E	Under Construction	Clinton	Lee	26.0	200-299	AC	615	2011
SERC-E	Under Construction	Denny Terrace	Pineland	8.0	200-299	AC	950	2011
SERC-E	Planned	Harris	RTP	22.0	200-299	AC	1,195	2014
SERC-E	Planned	Lyles	Denny Terrace	3.0	200-299	AC	950	2014
SERC-E	Planned	Lyles	Denny Terrace	3.0	200-299	AC	950	2014
SERC-E	Planned	Pepperhill	Summerville	7.0	200-299	AC	950	2013
SERC-E	Under Construction	Pleasant Garden (Duke)	Asheboro (Progress)	20.0	200-299	AC	1,175	2011
SERC-E	Under Construction	Richmond	Ft. Bragg Woodruff St	65.0	200-299	AC	1,195	2011
SERC-E	Under Construction	Rockingham	West End	38.0	200-299	AC	1,195	2011

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
SERC-E	Planned	St. George	Summerville	29.0	200-299	AC	950	2018
SERC-E	Planned	Urquhart	Graniteville	18.0	200-299	AC	950	2016
SERC-E	Planned	VC Summer #2	Lake Murray	23.0	200-299	AC	950	2015
SERC-E	Planned	VC Summer #2	St. George	135.0	200-299	AC	950	2018
SERC-E	Planned	VC Summer	Killian	38.0	200-299	AC	950	2015
SERC-E	Under Construction	VC Summer	VC Summer #2	1.0	200-299	AC	950	2013
SERC-E	Under Construction	VC Summer	VC Summer #2	1.0	200-299	AC	950	2013
SERC-E	Planned	VC Summer	VC Summer #2	1.0	200-299	AC	950	2018
SERC-E	Planned	Horse Gap Sub	New Watauga 230kV Sub	17.0	200-299	AC	402	2020
SERC-E	Planned	A M Williams	Cainhoy	11.0	200-299	AC	352	2013
SERC-E	Under Construction	Shiloh Sw Sta	Pisgah Tie	-	200-299	AC	850	2013
SERC-E	Planned	Canadys	St. George	(8.0)	200-299	AC	352	2018
SERC-E	Planned	Lyles	Denny Terrace	(3.0)	200-299	AC	510	2014
SERC-E	Planned	St. George	Summerville	(29.0)	200-299	AC	352	2018
SERC-E	Under Construction	VC Summer	Parr	(2.0)	200-299	AC	475	2013
SERC-E	Under Construction	VC Summer	Parr	(2.0)	200-299	AC	475	2013
SERC-N	Under Construction	Blackberry	Morgan	52.0	300-399	AC	870	2012
SERC-N	Under Construction	Blackberry	Neosho	8.0	300-399	AC	870	2012
SERC-N	Planned	Blackberry	Sportsman Acres	93.0	300-399	AC	1,369	2012
SERC-N	Planned	Choctaw	French Camp	-	400-599	AC	2,598	2015
SERC-N	Planned	Davidson	Pin Hook	-	400-599	AC	2,598	2012
SERC-N	Under Construction	Madison	Limestone	-	400-599	AC	2,598	2011
SERC-N	Planned	Shelby	Cordova	23.3	400-599	AC	1,732	2012
SERC-N	Planned	Shelby	Lagoon Creek	-	400-599	AC	2,598	2012
SERC-N	Under Construction	West Point	Clay	-	400-599	AC	2,598	2012
SERC-N	Planned	Wilson	Pin Hook	-	400-599	AC	2,598	2012
SERC-SE	Planned	Arnold Mill	Hopewell	12.0	200-299	AC	509	2016
SERC-SE	Planned	Autaugaville 6	Autaugaville 8	1.0	200-299	AC	1,614	2013
SERC-SE	Planned	Autaugaville 6	Autuagaville 8	1.0	200-299	AC	1,614	2013
SERC-SE	Planned	Barry	Chickasaw	-	200-299	AC	1,243	2016
SERC-SE	Planned	Barry	Crist	-	200-299	AC	693	2015
SERC-SE	Under Construction	Berkeley Lake	Spruill Road	-	200-299	AC	682	2018
SERC-SE	Planned	Bessemer	South Bessemer	-	200-299	AC	807	2021
SERC-SE	Planned	Bethabara	East Walton	8.0	200-299	AC	602	2015
SERC-SE	Planned	Blanford/Meldrim	McIntosh (black)	-	200-299	AC	1,024	2014
SERC-SE	Planned	Blanford/Meldrim	McIntosh (white)	-	200-299	AC	1,024	2014

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
SERC-SE	Planned	Bostwick	East Walton	4.0	200-299	AC	602	2015
SERC-SE	Planned	Boulevard	Dean Forest	-	200-299	AC	866	2015
SERC-SE	Planned	Branch	West Milledgeville	-	200-299	AC	829	2019
SERC-SE	Planned	Co line Rd	PSDF	-	200-299	AC	907	2019
SERC-SE	Planned	Cumming	Sharon Springs	7.0	200-299	AC	602	2015
SERC-SE	Planned	Dean Forest	GSW	5.0	200-299	AC	1,018	2015
SERC-SE	Planned	Dean Forest	Kraft	-	200-299	AC	866	2015
SERC-SE	Planned	Dorchester	Little Ogeechee	-	200-299	AC	1,205	2017
SERC-SE	Planned	Dorchester	West Brunswick	45.0	200-299	AC	1,018	2017
SERC-SE	Under Construction	Dresden	Heard County	6.0	400-599	AC	3,429	2014
SERC-SE	Planned	East Social Circle	Snellville Primary	-	200-299	AC	682	2018
SERC-SE	Planned	East Walton	Jack's Creek	9.0	200-299	AC	602	2015
SERC-SE	Planned	East Walton	Rockville	40.0	400-599	AC	3,464	2015
SERC-SE	Planned	East Walton	South Hall	35.0	400-599	AC	3,429	2020
SERC-SE	Planned	Ellicot TS	Georgetown D.S.	-	200-299	AC	693	2021
SERC-SE	Planned	Ellicott TS	SSAB	6.0	200-299	AC	807	2021
SERC-SE	Under Construction	Flat Shoals	Uniion City	-	200-299	AC	807	2011
SERC-SE	Planned	Gaston	Boyles	1.0	200-299	AC	502	2021
SERC-SE	Planned	Gaston	East Pelham	-	200-299	AC	502	2014
SERC-SE	Planned	Gaston	Roopville	-	200-299	AC	602	2012
SERC-SE	Planned	Gaston	Yellowdirt	-	200-299	AC	602	2014
SERC-SE	Planned	Highland City	Callaway	4.0	200-299	AC	602	2015
SERC-SE	Planned	Holt	Tuscaloosa	7.0	200-299	AC	807	2011
SERC-SE	Planned	Hopewell	McGrauFord (black)	11.0	200-299	AC	509	2018
SERC-SE	Planned	Jack McDonough	Northwest	-	200-299	AC	602	2013
SERC-SE	Planned	Jack McDonough	Northwest	-	200-299	AC	602	2013
SERC-SE	Planned	Jack's Creek	Cornish Mountain	20.0	200-299	AC	602	2019
SERC-SE	Under Construction	Kemper IGCC	Lauderdale East	18.0	200-299	AC	752	2012
SERC-SE	Under Construction	Kemper IGCC	Lauderdale West	20.0	200-299	AC	752	2013
SERC-SE	Under Construction	Kiln	Carriere SW	9.0	200-299	AC	602	2011
SERC-SE	Under Construction	Kiln	Carriere SW	17.0	200-299	AC	602	2011
SERC-SE	Planned	Kraft	McIntosh (black)	-	200-299	AC	1,018	2012
SERC-SE	Planned	Kraft	McIntosh (white)	-	200-299	AC	1,024	2012
SERC-SE	Planned	Laguna Beach	Santa Rosa	21.0	200-299	AC	602	2015
SERC-SE	Planned	Laguna Beach	Santa Rosa	21.0	200-299	AC	602	2015
SERC-SE	Planned	Lansing Smith	Laguna Beach	14.0	200-299	AC	602	2012

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
SERC-SE	Under Construction	Lauderdale East	Vimville	6.0	200-299	AC	602	2014
SERC-SE	Planned	Lawrenceville	Winder	-	200-299	AC	833	2017
SERC-SE	Planned	Montg SS	South Montg	-	200-299	AC	403	2012
SERC-SE	Planned	Norcross	Berkeley Lake	-	200-299	AC	682	2015
SERC-SE	Planned	North Tifton	Pine Grove	-	200-299	AC	704	2019
SERC-SE	Planned	O'Hara	McDonough Primary	20.0	200-299	AC	602	2018
SERC-SE	Planned	Orange Grove	Moss Point East	-	200-299	AC	752	2020
SERC-SE	Planned	Parkaire	Roswell	5.0	200-299	AC	602	2018
SERC-SE	Planned	Plant Daniel	Moss Point East	-	200-299	AC	865	2011
SERC-SE	Under Construction	Plant McDonough CC	Plant McDonough (black)	1.0	200-299	AC	1,205	2011
SERC-SE	Under Construction	Plant McDonough CC	Plant McDonough (white)	1.0	200-299	AC	1,205	2011
SERC-SE	Planned	Snowdoun TS	Pike Co	-	200-299	AC	807	2014
SERC-SE	Planned	South Dahlonega	Palmer Creek	10.0	200-299	AC	602	2015
SERC-SE	Planned	SSAB	Kushla S.S.	-	200-299	AC	693	2021
SERC-SE	Under Construction	Vimville	Sweatt	14.0	200-299	AC	602	2014
SERC-SE	Planned	Vogtle	Thomson	60.0	400-599	AC	2,701	2016
SERC-SE	Planned	Vogtle	Wilson	-	200-299	AC	1,018	2019
SERC-SE	Planned	Wadley	Waynesboro	-	200-299	AC	718	2019
SERC-SE	Planned	Waynesboro	Wilson	-	200-299	AC	866	2020
SERC-W	Under Construction	Bayou Laboutte	Iberville	2.0	200-299	AC	800	2011
SERC-W	Under Construction	Sellers Road	Meaux	10.0	200-299	AC	829	2011
SERC-W	Planned	Moss Bluff	Lake Charles	15.0	200-299	AC	711	2019
SERC-W	Planned	Nelson	Moss Bluff	7.0	200-299	AC	704	2012
SERC-W	Planned	Oakville	Alliance	10.0	200-299	AC	515	2012
SERC-W	Planned	Segura	Moril	1.0	200-299	AC	497	2011
SERC-W	Under Construction	Tillatoba	South Grenada	19.0	200-299	AC	500	2012
SERC-W	Planned	Bayou Steel	Tezcuco	10.0	200-299	AC	520	2013
SERC-W	Planned	Church Rd	Getwell	16.0	200-299	AC	520	2013
SERC-W	Under Construction	Labbe	Sellers Road	15.0	200-299	AC	829	2012
SERC-W	Under Construction	Jacinto	Lewis Creek	29.0	200-299	AC	501	2011
SERC-W	Under Construction	McAdams	Pickens	-	200-299	AC	797	2011
SERC-W	Planned	Waterford	Ninemile	-	200-299	AC	1,038	2011
SERC-W	Under Construction	Hartburg	Inland Orange	-	200-299	AC	685	2011
SERC-W	Under Construction	Inland Orange	McLewis	-	200-299	AC	685	2011
SERC-W	Under Construction	McLewis	Helbig	-	200-299	AC	685	2011
SERC-W	Under Construction	Sabine	Mid County	-	200-299	AC	637	2011

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
SERC-W	Under Construction	Addis	Cajun	-	200-299	AC	637	2011
SERC-W	Planned	Hartburg	McLewis	-	200-299	AC	785	2011
SPP	Planned	Shipe Road	E. Rogers	9.0	300-399	AC	1,336	2016
SPP	Planned	E. Rogers	Osage	32.0	300-399	AC	1,336	2016
SPP	Planned	Sunnyside	Hugo	120.0	300-399	AC	1,793	2012
SPP	Planned	Bonin 6 (502403)	Labbe (502421)	1.4	200-299	AC	655	2012
SPP	Planned	Woodward EHV	Border	72.0	300-399	AC	1,793	2014
SPP	Planned	Wells	Labbe	30.0	200-299	AC	829	2013
SPP	Planned	Flint Creek	Shipe Road	18.0	300-399	AC	1,336	2014
SPP	Planned	Harrington	Cherry St. Intg.	5.3	200-299	AC	452	2013
SPP	Planned	Cherry St. Intg.	Potter County	6.0	200-299	AC	452	2013
SPP	Planned	SIBLEY	MARYVILLE	105.0	300-399	AC	1,792	2017
SPP	Planned	MARYVILLE	NEBRASKA	70.0	300-399	AC	1,792	2017
SPP	Planned	IATAN	NASHUA	30.0	300-399	AC	2,546	2015
SPP	Planned	Hitchland	Moore County	50.0	200-299	AC	452	2011
SPP	Planned	Randall County	Amarillo South	8.5	200-299	AC	452	2013
SPP	Planned	Turk	NW Texarkana	33.0	300-399	AC	1,336	2012
SPP	Planned	Axtell	Post Rock	125.0	300-399	AC	1,792	2013
SPP	Under Construction	Richard	Sellers Road	32.0	200-299	AC	829	2011
SPP	Planned		Hitchland	46.0	300-399	AC	829	2014
SPP	Under Construction	Sellers Road	Segura	19.0	200-299	AC	829	2011
SPP	Planned	Sooner	Rose Hill	80.0	300-399	AC	1,793	2013
SPP	Planned	Hitchland	OGE Woodward Substation	30.0	300-399	AC	1,800	2014
SPP	Planned	TUCO	OGE Woodward Substation	180.0	300-399	AC	1,355	2014
SPP	Planned	Oasis	Pleasant Hill	30.0	200-299	AC	452	2014
SPP	Planned	Sooner	Cleveland	35.2	300-399	AC	1,793	2012
SPP	Planned	Valliant 345 kV	NW Texarkana 345 kV	79.0	300-399	AC	1,793	2014
SPP	Planned	Potter County	Newhart Intg.	68.0	200-299	AC	452	2013
SPP	Planned	Newhart Intg.	Plant X	36.0	200-299	AC	452	2013
SPP	Planned			46.0	300-399	AC	146	2014
SPP	Planned	Newhart Intg.	Swisher County	19.0	200-299	AC	452	2014
SPP	Planned	Hitchland	Ochiltree Intg.	32.0	200-299	AC	452	2011
SPP	Planned	Seminole	Muskogee	100.0	300-399	AC	1,793	2013
SPP	Planned	Roosevelt County	Pleasant Hill	30.0	200-299	AC	452	2014
SPP	Under Construction	Rose Hill	Sooner	100.0	300-399	AC	1,611	2012
WECC	Planned	Genesee AB	Langdon AB	225.0	400-599	DC	3,000	2014

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
WECC	Planned	Heartland AB	28S	310.0	400-599	DC	3,000	2013
WECC	Planned	Genesee AB	Livock	304.0	400-599	AC	3,500	2016
WECC	Planned	Livock	Thickwoods AB	304.0	400-599	AC	3,500	2016
WECC	Planned	Heartland AB	Ellerslie AB	50.0	400-599	AC	3,500	2013
WECC	Planned	Heartland AB	Deerland	17.0	200-299	AC	754	2013
WECC	Planned	Chapelrock	Fidler	24.0	200-299	AC	1,275	2014
WECC	Planned	Fidler	103S	24.0	200-299	AC	1,275	2014
WECC	Planned	103S	Journault	19.0	200-299	AC	1,103	2014
WECC	Planned	Journault	Picture Butte	32.0	200-299	AC	1,103	2014
WECC	Planned	Journault	Whitla	60.0	200-299	AC	1,103	2015
WECC	Planned	Whitla	Bowmanton	55.0	200-299	AC	1,275	2014
WECC	Planned	Cassils	Bowmanton	85.0	200-299	AC	1,275	2014
WECC	Planned	Peigan	Foothills	150.0	200-299	AC	-	2014
WECC	Planned	Foothills	SS-65	29.0	200-299	AC	-	2014
WECC	Planned	SS-65	Janet	11.0	200-299	AC	-	2014
WECC	Planned	Foothills	Sarcee	60.9	200-299	AC	-	2015
WECC	Planned	650S	932S	37.0	200-299	AC	1,103	2012
WECC	Planned	932S	959S	42.0	200-299	AC	1,103	2012
WECC	Planned	959S	946S	54.0	200-299	AC	1,103	2012
WECC	Planned	946S	963S	22.0	200-299	AC	1,103	2012
WECC	Planned	28S	132S	23.0	200-299	AC	1,275	2012
WECC	Planned	946S	801S	4.0	200-299	AC	1,103	2012
WECC	Planned	Picture Butte	Montana	326.0	200-299	AC	300	2012
WECC	Planned	Midpoint, ID	King, ID	24.0	200-299	AC	351	2012
WECC	Planned	King, ID	DRAM, ID	80.0	200-299	AC	351	2012
WECC	Planned	Midpoint, ID	DRAM, ID	(104.0)	200-299	AC	351	2012
WECC	Under Construction	Ontario, OR	South of New Plymouth, ID	13.0	200-299	AC	493	2012
WECC	Under Construction	South of New Plymouth, ID	Caldwell, ID	23.0	200-299	AC	493	2012
WECC	Under Construction	Ontario, OR	Caldwell, ID	(30.0)	200-299	AC	493	2012
WECC	Planned	Reno NV	Dayton NV	17.0	300-399	AC	600	2012
WECC	Planned	Carson Lake, NV	Fallon, NV	20.0	200-299	AC	200	2013
WECC	Planned	Reno NV	Doyle CA	50.0	300-399	AC	600	2018
WECC	Planned	Dayton NV	Reno NV	15.0	300-399	AC	600	2018
WECC	Planned	Nicola BC	Meridian BC	153.0	400-599	AC	2,600	2014
WECC	Planned	Skeena, BC	Bob Quinn, BC	211.0	200-299	AC	-	2013
WECC	Planned	Invermere, BC	Goldon, BC	74.0	200-299	AC	-	2012

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
WECC	Planned	Sundance, BC	Bear Mountain, BC	37.0	200-299	AC	-	2013
WECC	Planned	Sundance, BC	Bear Mountain, BC	37.0	200-299	AC	-	2013
WECC	Planned	Mica, BC	Nicola, BC	-	400-599	AC	-	2014
WECC	Planned	Ashton Creek, BC	Vassuax Lake, BC	-	400-599	AC	-	2014
WECC	Planned	Site C, BC	Peace Canyon	-	400-599	AC	-	2020
WECC	Planned	Cathedral Square	Sperling (via Mount Pleasant)	8.2	200-299	AC	-	2012
WECC	Planned	Ingledow, BC	Mclellan (via Fleetwood)	16.0	200-299	AC	-	2014
WECC	Planned	Horne Payne	West End-via Murrin, Cathedral	10.4	200-299	AC	-	2019
WECC	Planned	Como Lake	Murrin (via Horne Payne)	26.8	200-299	AC	-	2018
WECC	Under Construction	V. Lake Terminal BC	R.G. Anderson BC	17.0	200-299	AC	506	2011
WECC	Under Construction	V. Lake Terminal BC	R.G. Anderson BC	17.0	200-299	AC	506	2011
WECC	Under Construction	V. Lake Terminal BC	Bentley BC	7.0	200-299	AC	506	2011
WECC	Under Construction	Table Mountain Substation	Rio Oso Substation	136.0	200-299	AC	604	2011
WECC	Planned	Vaca Dixon Substation	Birds Landing Switch Stn.-Rio	50.0	200-299	AC	754	2011
WECC	Planned	Newark Substation	Ravenswood Substation	18.0	200-299	AC	1,366	2014
WECC	Under Construction	Lakeville Substation (Petaluma)	Lakeville Substation (Petaluma)	0.5	200-299	AC	658	2011
WECC	Planned	Rector CA	Springville CA	38.0	200-299	AC	1,287	2014
WECC	Planned	Tehachapi CA	Mira Loma CA	250.0	400-599	AC	3,421	2015
WECC	Planned	Tehachapi CA	Mohave CA	10.0	200-299	AC	1,287	2011
WECC	Under Construction	Suncrest	Sycamore Canyon	6.2	200-300	AC	-	2012
WECC	Under Construction	Suncrest	Sycamore Canyon	28.0	200-299	AC	1,326	2012
WECC	Under Construction	Suncrest	Sycamore Canyon	6.2	200-300	AC	-	2012
WECC	Under Construction	Suncrest	Sycamore Canyon	28.0	200-299	AC	1,326	2012
WECC	Under Construction	Imperial Valley	Suncrest	91.0	400-599	AC	2,250	2012
WECC	Planned	SG&E/IID's, Imperial Valley Sub	IID's El Centro Switching Station	8.0	200-299	AC	654	2011
WECC	Planned	IID's Midway station	8.5 miles west of Midway	8.5	200-299	AC	654	2011
WECC	Planned	Scattergood Generating	Olympic Receiving Station K	12.0	200-299	AC	500	2014
WECC	Planned	Phoenix AZ	Phoenix AZ	15.0	400-599	AC	1,000	2013
WECC	Planned	Phoenix AZ	Phoenix AZ	6.0	200-299	AC	1,200	2014
WECC	Planned	West Phoenix AZ	West Phoenix AZ	15.0	200-299	AC	1,200	2014
WECC	Planned	Wintersburg AZ	Yuma AZ	115.0	400-599	AC	1,200	2014
WECC	Planned	West Phoenix AZ	West Phoenix AZ	12.0	200-299	AC	1,200	2015
WECC	Planned	West Phoenix AZ	West Phoenix AZ	12.0	200-299	AC	1,200	2015
WECC	Planned	Northwest of Phoenix AZ	Peoria AZ	40.0	400-599	AC	1,200	2016
WECC	Planned	Northwest of Phoenix AZ	West Phoenix AZ	28.0	400-599	AC	-	2014
WECC	Planned	Yuma AZ	Yuma AZ	11.0	200-299	AC	-	2014

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		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
WECC	Planned	Coolidge, AZ	Mesa, AZ	-	400-599	AC	1,405	2011
WECC	Planned	Coolidge, AZ	Florence, AZ	30.0	200-299	AC	875	2011
WECC	Planned	Florence, AZ	Queen Creek, AZ	13.0	200-299	AC	875	2011
WECC	Planned	Maricopa AZ	Mesa AZ	87.0	200-299	AC	1,405	2014
WECC	Planned	Maricopa AZ	Mesa AZ	(87.0)	200-299	AC	1,405	2014
WECC	Planned	Maricopa AZ	Mesa AZ	87.0	400-599	AC	1,405	2013
WECC	Planned	Queen Creek AZ	Florence AZ	10.0	200-299	AC	875	2019
WECC	Planned	Casa Grande, AZ	Coolidge AZ	21.0	200-299	AC	833	2014
WECC	Planned	Maricopa AZ	Coolidge, AZ	-	400-599	AC	1,405	2013
WECC	Planned	Corona, NM	Coolidge AZ	500.0	400-599	AC	3,000	2015
WECC	Planned	Shiprock, NM	La Plata County, CO	40.0	200-299	AC	613	2012
WECC	Under Construction	West Mesa	B-A	-	300-399	AC	270	2011
WECC	Planned	San Juan	B-A	-	300-399	AC		2013
WECC	Under Construction	Las Vegas NV	Las Vegas NV	1.0	400-599	AC	3,585	2011
WECC	Planned	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	1,200	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	1,200	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	18.0	200-299	AC	810	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	18.0	200-299	AC	810	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	4.0	200-299	AC	810	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	8.0	400-599	AC	3,000	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	8.0	400-599	AC	3,000	2018
WECC	Planned	Las Vegas NV	Las Vegas NV	5.0	200-299	AC	810	2018
WECC	Planned	Robinson Summit 500 kV	Harry Allen 500 kV	280.0	400-599	AC	2,000	2012
WECC	Planned	Midpoint 500 kV	Robinson Summit 500 kV	235.0	400-599	AC	2,000	2013
WECC	Planned	Harry Allen 500 kV	Eldorado 500 kV	60.0	400-599	AC	2,000	2013
WECC	Planned	Stirling Mountain NV	Northwest NV	47.0	200-299	AC	320	2012
WECC	Planned	Stirling Mountain NV	Vista NV	25.0	200-299	AC	320	2012
WECC	Planned	Vista NV	Pahrump NV	11.0	200-299	AC	320	2012
WECC	Planned	O'Banion CA	Elverta CA	26.0	200-299	AC	600	2012
WECC	Planned	Blue Lake	Gresham	4.2	200-299	AC	418	2017
WECC	Planned	Horizon	Keeler	1.0	200-299	AC	697	2012
WECC	Planned	Trojan	Horizon	40.0	200-299	AC	500	2015
WECC	Planned	Coyote Springs	Bethel	200.0	400-599	AC	1,500	2015
WECC	Under Construction	Umatilla, OR	Rufus, OR	79.0	400-599	AC	3,420	2012
WECC	Planned	The Dalles, OR	Goldendale, WA	28.0	400-599	AC	-	2013
WECC	Planned	Clyde, WA	Central Ferry, WA	38.0	400-599	AC	-	2013

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
WECC	Planned	Castle Rock, WA	Troutdale, OR	70.0	400-599	AC	-	2015
WECC	Planned	Townsend MT	Midpoint, ID	460.0	400-599	AC	1,500	2015
WECC	Planned	Douglas Switchyard	Rapids Switchyard	15.0	200-299	AC	555	2013
WECC	Planned	Central, UT	St.George,UT	40.0	300-399	AC	600	2019
WECC	Under Construction	South Jordan, UT	SLC,UT	-	300-399	AC	1,398	2011
WECC	Planned	Sigurd, UT	Central,UT	165.0	300-399	AC	1,163	2014
WECC	Planned	Carbon County, WY	Mona, UT	400.0	400-599	AC	3,682	2018
WECC	Planned	Mona, UT	Tooele County,UT	65.0	300-399	AC	3,682	2013
WECC	Planned	Tooele County, UT	South Jordan, UT	32.0	300-399	AC	1,396	2013
WECC	Planned	South Jordan, UT	SLC,UT	28.0	300-399	AC	1,332	2014
WECC	Planned	Windstar,WY	Carbon County, WY	76.0	200-299	AC	888	2015
WECC	Planned	Windstar,WY	Carbon County, WY	122.0	200-299	AC	888	2015
WECC	Planned	Carbon County, WY	Rock Springs, WY	154.0	400-599	AC	3,682	2015
WECC	Planned	Rock Springs, WY	Rock Springs, WY	154.0	400-599	AC	3,682	2015
WECC	Planned	Rock Springs, WY	Downey, ID	203.0	400-599	AC	3,682	2015
WECC	Planned	Rock Springs, WY	Downey, ID	203.0	400-599	AC	3,682	2015
WECC	Planned	Carbon County, WY	Mona, UT	400.0	400-599	AC	3,682	2018
WECC	Planned	Mona, UT	Sigurd, UT	44.0	400-599	AC	3,682	2018
WECC	Planned	Sigurd, UT	Red Butte, UT	184.0	400-599	AC	3,682	2018
WECC	Planned	Sigurd, UT	Hurricane, Utah	170.0	300-399	AC	1,163	2019
WECC	Planned	Aeolus, WY	Dave Johnston substation,WY	70.0	200-299	AC	888	2015
WECC	Planned	Red Butte, UT	Clark County, NV	95.0	400-599	AC	3,682	2018
WECC	Planned	Yakima ,WA	Yakima ,WA	37.4	200-299	AC	-	2012
WECC	Planned	Wallawalla, WA	Wallula, WA	25.0	200-299	AC	600	2017
WECC	Planned	Wallawalla, WA	McNary, OR	31.0	200-299	AC	600	2012
WECC	Planned	Grants Pass, OR	Grants Pass, OR	30.0	200-299	AC	-	2016
WECC	Planned	Sedro Woolley WA	Snohomish WA	38.5	200-299	AC	831	2011
WECC	Planned	Sumner WA	Puyallup WA	8.0	200-299	AC	733	2012
WECC	Planned	Sammamish WA	Renton WA	16.0	200-299	AC	-	2015
WECC	Planned	Lacey WA	Lacey WA	10.0	200-299	AC	-	2013
WECC	Planned	Craig, CO	Rifle, CO	98.4	200-299	AC	-	2012
WECC	Planned	Osage 230 kV Bus	Lange 230 kV Bus	75.0	200-299	AC	554	2015
WECC	Planned	Teckla 230 kV Bus	Osage 230 kV Bus	60.0	200-299	AC	554	2014
WECC	Planned	Midway CO	Waterton CO	82.0	300-399	AC	1,200	2011
WECC	Planned	Comanche CO	Missile Site CO	660.0	300-399	AC	1,733	2017
WECC	Planned	Pawnee CO	Smoky Hill CO	96.0	300-399	AC	735	2013

Assessment Area	Status	Terminal Location		Line Length	Operating Voltage	Current	Capacity Rating	Expected In-Service
		From	To	(Circuit Miles)	(kV)	(AC/DC)	(MVA)	(Year)
WECC	Under Construction	Fordham	Fort St. Vrain	27.6	200-299	AC	398	2011
WECC	Under Construction	Fordham	Fort St. Vrain	15.2	200-299	AC	398	2011
WECC	Under Construction	Fort Collins CO	Loveland CO	2.4	200-299	AC	472	2012
WECC	Under Construction	Fort Collins CO	Loveland CO	6.9	200-299	AC	472	2012
WECC	Planned	Osage WY	Rapid City SD	65.0	200-299	AC	558	2015
WECC	Planned	Teckla WY	Osage WY	70.0	200-299	AC	558	2013
WECC	Planned	Alamosa County, CO	Huerfano County, CO	93.0	200-299	AC	613	2013
WECC	Planned	Huerfano County, CO	Pueblo, CO	43.0	300-399	AC	1,700	2013
WECC	Planned	Huerfano County, CO	Pueblo, CO	7.0	200-299	AC	613	2013
WECC	Planned	Burlington, CO	Wray, CO	56.0	200-299	AC	613	2012
WECC	Planned	Archuleta County, CO	Durango CO	29.0	200-299	AC	613	2012
WECC	Planned	Shiprock, NM	La Plata County, CO	40.0	200-299	AC	613	2012
WECC	Planned	Cheyenne, WY	Cheyenne, WY	10.0	200-299	AC	613	2013
WECC	Planned	La Jovita MX	Presidente Juarz MX	38.0	200-299	AC	430	2012
WECC	Planned	La Jovita MX	El Ciprés MX	35.0	200-299	AC	430	2012
WECC	Planned	La Jovita MX	Lomas MX	30.0	200-299	AC	430	2012
WECC	Planned	Mexicali MX	Tecnologico MX	10.0	200-299	AC	388	2013
WECC	Planned	La Jovita MX	La Herradura MX	50.0	200-299	AC	430	2015
WECC	Planned	El Cañon MX	El Ciprés MX	52.0	200-299	AC	430	2016

Appendix VII: NERC-Wide Transformer Additions, Upgrades, and Retirements

Table Notes

Note 1: All transformer projects are included (*Under Construction*, *Planned*, and *Conceptual*) transformer projects are included with in-service dates between 2011 and 2021.

Note 2: A comprehensive list, including detailed information about each project, will be published in the 2011 NERC Electricity Supply and Demand (ES&D) Database.[383]

[383] NERC ES&D Website: http://www.nerc.com/page.php?cid=4%7C38.

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
ERCOT	Loma Alta 345kV station and autotransformer	345	138	May-2018	Construct a 345 substation and connect to the existing Loma Alta 138 substation.
ERCOT	Ranchito, New SS with 345/138 kV autotransformer	345	138	December-2017	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
ERCOT	Mountain Top-Blanco-Devil's Hill	138	69	December-2012	Close the 69-kV switch (SW 458) at the Blanco substation(7482) to loop the load located at the Blanco substation. Upgrade the capacity of the 138-69-kV auto-transformer (T2) at the Devil's Hill substation(7493) from 20-MVA to 45-MVA.
ERCOT	Magruder: Add 138/69 kV, 187 MVA, auto, 3 breaker 138 kV ringbus, 1 69 kV lowside breaker	138	69	September-2014	Reconductor Victoria to North Victoria and North Victoria to Magruder 69 kV line to 1590 ACSR. Install 138/69 kV, 187 MVA, autotransformer at Magruder on the Victoria to Thomaston 138kV line.
ERCOT	Trinity Switch 345/138 kV autotransformer	345	138	May-2018	Create Trinity Switch and install a 600 MVA 345/138 kV autotransformer
ERCOT	Lytle: Add 138/69 kV Auto	138	69	May-2013	Add CPS Lytle to ETT Lytle 795 ACSR 138 kV line and 93 MVA 69/138 kV autotransformer at Lytle
ERCOT	2nd Lewisville Auto	345	138	June-2012	Install (2nd) 345/138 kV autotransformer at Lewisville station
ERCOT	Lavon 345/138 kV Switching Station	345	138	May-2018	Construct 345/138 kV switching station
ERCOT	Frontera, add SS with 345/138 kV autotransformer	345	138	October-2016	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
ERCOT	South McAllen, new SS with 345/138 kV autotransformer	345	138	December-2016	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
ERCOT	North Lake 345/138 kV autotransformer	345	138	May-2018	Install a 345/138 kV autotransformer
ERCOT	Melon Creek: Install 138/69 KV Auto	138	69	March-2014	Construct Melon Creek substation on Airco to Rincon 138 kV line with 138/69 kV, 93 MVA, auto. Build new 69 kV line from Melon Creek to Tatton. Rebuild 69 kV line from Refugio to Tatton.
ERCOT	Collin 345/138 kV autotransformer	345	138	May-2013	Install second 345/138 kV autotransformer
ERCOT	Bonham Switching Station 138/69 kV autotransformer replacement	138	69	May-2018	Replace existing 138/69 kV autotransformer

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
ERCOT	Oleander, Construct 138/69 kV Substation	138	69	May-2011	Construct a new 138/69 kV Switching Station near East Harrison substation and reconductor the 69 kV line from La Palma to San Benito
ERCOT	Alamito Creek, add 2nd 138/69 kV auto	138	69	April-2011	Add 2nd 138/69 kV autotransformer at Alamito Creek, and install a NaS Battery at Gonzales
ERCOT	Stoney Ridge 138kV substation (original title is Linda Vista substation)	138	69	December-2011	Establish new 138kV Stoney Ridge substation and install (2) 30MVA transformers. The substation will cut into Ckt 962 (Garfield to Onion Creek).
ERCOT	Rinard Creek 138kV substation	138	69	June-2014	Establish a new 138kV Rinard Creek substation with (2) 30MVA transformers. The substation will cut into existing Ckt 987 (Lytton Springs to Slaughter Lane).
ERCOT	Mueller 138kV substation	138	69	October-2011	Establish a new 138kV Mueller substation with one 30MVA transformer and two underground feeders. The substation will cut into existing Ckt 938 (Kingsbery to Wheless Lane).
ERCOT	Dunlap 138/345kV Autotransformer Project	345	138	June-2013	Instal one 138/345 kV 672 MVA autotransformer at the Dunlap substation, configuring a Dunlap to Lost Pines 345 kV circuit, add a new 345kV line from Dunlap to Austrop and combine 138kv Dunlap to Decker and Decker to Techridge into one single circuit bypassing Decker.
ERCOT	Leon Switch #2 138/69 kV autotransformer replacement	138	69	May-2018	Replace existing 138/69 kV autotransformer
ERCOT	Royse 138/69 kV autotransformer	138	69	May-2017	Install larger autotransformer
ERCOT	Thomaston: Install 138 kV PST, Add 3-28.8 MVAR Cap Banks, Reterminate 138 kV Line	138	69	May-2011	Upgrade Thomaston substation to 3 breaker ring bus, install 180/200 MVA PST on Thomaston to LCRA Cuero 138 kV line.
ERCOT	Killeen Switch	345	138	December-2013	Install circuit breakers, capacitors and second 345/138 kV autotransformer
ERCOT	Rio Bravo, 345 kV SS with 345/138 kV autotransformer	345	138	March-2018	Construct 345 kV line from Lobo to Rio Bravo and add 345/138 kV substation at Rio Bravo with 345/138 kV autotransformer
ERCOT	Rainey St 138kV substation	138	69	June-2016	Establish a new 138kV Rainey St substation with (2) 50MVA transformers. The substation will cut into existing Ckt 1015 (Pedernales to Seaholm).
ERCOT	Dunlap 138kV substation	138	69	April-2012	Establish a new 138kV Dunlap substation with one 30MVA transformer. The substation will cut into existing Ckt 921 (Austrop - Decker).
ERCOT	Northeast 138kV Substation	138	69	June-2016	Establish a 138kV substation with (2) 30MVA transformers and 4 distribution circuits with underground get-a-ways. The station will cut into existing Gilleland - Techridge line.

Assessment Area	Transformer Project Name	Voltage		In-Service Date	Description / Status
		High-Side (kV)	Low-Side (kV)	(Month-Year)	
ERCOT	GPLTemp-Shiloh 69kV line and Shiloh 138kV substation rebuild and install a 138 kV/69 kV autotransformer (75 MVA)	138	69	June-2012	Line upgrade and substation rebuild with installing a 138 kV/69 kV autotransformer (75 MVA) at Shiloh substation
ERCOT	Cagnon	345	138	June-2013	Install a Third 345kV 600 MVA Autotransformer.
ERCOT	Thompson Creek Substation	138	69	March-2011	Install (3) Breaker ring to include (1) 138 lines, (1) 14MVA 138/69 auto transformer, and (1) 138/12.5 transformer
ERCOT	Sargent Road 345/138 kV autotransformer	345	138	May-2015	Install second 345/138 kV autotransformer
ERCOT	Central Bluff Switch	345	138	December-2011	Construct 345 kV switching station with 345/138 kV autotransformers
ERCOT	Norwood Switch autotransformer	345	138	May-2014	Replace #1 345/138 kV autotransformer
ERCOT	Hearne Auto	138	69	May-2011	Replace 60 MVA, 138/69 kV auto with 100 MVA auto
ERCOT	Olney 2nd Auto	138	69	May-2011	Add 60 MVA, 138/69 kV auto
ERCOT	Hilltop Lakes Auto	138	69	April-2011	Replace 40 MVA, 138/69 kV auto with 60 MVA auto
ERCOT	Bruni auto upgrade	138	69	April-2011	Upgrade the 18 MVA138/69 kV autotransformer.
ERCOT	Graham 138 kV terminal equipment	138	69	May-2011	Upgrade terminal equipment on 345/138 kV autotransformer
ERCOT	Laguna: Add 138/69 kV Auto	138	69	December-2013	Construct new 138 kV line and add tranformation at Laguna to remove contingency overloads during off-peak maintnenance
ERCOT	Pleasant Valley	138	69	May-2013	Install second 138/69 kV autotransformer
ERCOT	North McCamey Autotransformer	345	138	June-2013	Add two new 345-138 kV 800 MVA autotransformer at the North McCamey substation.
ERCOT	Kendall Autotransformer Replacement	345	138	December-2011	Replace the existing 345/138 kV 336 MVA autotransformer with an 800 MVA autotransformer at the Kendall Substation.
ERCOT	Illinois #4, Build new three breaker ring bus & add 138/69 kV auto	138	69	February-2012	Rebuild 69 kV line from Ft. Lancaster to Hamilton Rd. with 795 ACSS, double circuit capable as alternative to CREZ project of rebuilding Sonora to Hamilton 138 kV line
ERCOT	Scurry County South Switch (Central A)	345	138	June-2011	Construct 345 kV switching station with 345/138 kV autotransformers and shunt reactor
ERCOT	Dermott Switch (Central B)	345	138	June-2011	Construct 345 kV switching station with 345/138 kV autotransformers and shunt reactor
ERCOT	Zenith 138kV	345	138	May-2012	Expand Zenith substation with addition of 345/138kV 800MVA Autotransformer. Build a new 138kV double circuit line from Zenith to Gertie corner.

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
ERCOT	Anna Switch 345/138 kV autotransformer replacement	345	138	May-2013	Replace #1 autotransformer
ERCOT	Forney Sw. Sta. Second 600 MVA, 345/138 kV Autotransformer	345	138	May-2014	Add second 345/138 autotransformer
ERCOT	Whitney 2nd Auto	138	69	June-2012	Add 75 MVA, 138/69 kV auto
ERCOT	De-energization of Crosby - Mont Belvieu Ckt. 43	138	69	June-2012	De-energize Ckt. 43 Crosby - Mont Belvieu. Remove autotransformers from Crosby and Mont Belvieu. Move Highlands tap from Ckt. 43 to Ckt. 66 Haney - Baytown.
ERCOT	Pearsall auto upgrade	138	69	May-2012	Upgrade the 50 MVA138/69 kV autotransformer.
ERCOT	Elroy 138kV Unit Transformer	138	69	January-2012	Establish one 30MVA transformer at LCRA owned 138kV Elroy substation
ERCOT	Southeast Nacogdoches 345/138 kV	345	138	May-2012	Replace existing 345/138 kV autotransformer with larger autotransformer
ERCOT	Ranchito: Build 138 kV station with 138 KV Auto and Ring Bus	138	69	December-2017	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
ERCOT	Zorn Autotransformer Addition	345	138	December-2012	Add a new 345-138 kV 478 MVA at Zorn substation (7042).
ERCOT	Wellborn Switching Sub	138	69	September-2012	Install (3) Breaker ring to include (2) 138 lines and (1) 138/69 auto transformer relocated from Greens Prairie
ERCOT	Hill Country - Install Fourth 345/138 kV	345	138	June-2012	Install 600 MVA autotransformer at Hill Country
ERCOT	Cedar Hill Switch second 345/138 kV autotransformer	345	138	May-2019	Install autotransformer
ERCOT	Bullick Hollow 138kV Substation	138	69	January-2013	Establish a new substation with (2) 50MVA unit transformers to serve the Water Treatment Plant
ERCOT	Kendall Autotransformer Addition	345	138	June-2013	Replace the existing 345-138 kV 478MVA autotransformer with an 672 MVA autotransformer at the Kendall substation.
ERCOT	Cagnon - Install a Fourth 345kV Autotransformer	345	138	June-2014	Install one 600 MVA autotransformer.
ERCOT	Muenster to Red River	138	69	June-2014	Add 60 MVA 138/69 kV auto at Munester. Build 11 miles of 795 ACSR line to Red River.
MISO	North Mankato 115 kV project	345	115	June-2011	Helena
MISO	City of Redwood Falls, MN	345	115	December-2011	Tap Existing Area Line - load serving upgrades
MISO	Fargo, ND - St Cloud/Monticello, MN	345	230	March-2015	Bison; Fargo, ND - St Cloud/Monticello, MN area 345 kV project
MISO	Fargo, ND - St Cloud/Monticello, MN	345	115	May-2013	Alexandria SS - Fargo, ND - St Cloud/Monticello, MN area 345 kV project
MISO	Fargo, ND - St Cloud/Monticello, MN	345	115	December-2011	Quarry (St. Cloud)- Fargo, ND - St Cloud/Monticello, MN area 345 kV
MISO	Fargo, ND - St Cloud/Monticello, MN	345	115	December-2011	Monticello (Replacement) - St Cloud/Monticello, MN area 345 kV project
MISO	Rockdale-West Middleton 345 kV	345	138	June-2013	Cardinal (formerly West Middleton) 345/138
MISO	Rockdale-West Middleton 345 kV	345	138	June-2013	Cardinal (formerly West Middleton) 345/138

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
MISO	Monroe County - Council Creek projects	161	138	June-2013	Council Creek 161-138 kV
MISO	Weeds Lake	345	138	June-2013	Weeds lake 345/138 kV
MISO	Westwood Bk1 Limiting Equipment	345	138	June-2015	Westwood Bk1 (Replacement)
MISO	Winger	230	115	December-2014	Winger 230-115 kV (Replacement); Transformer Upgrade
MISO	SE Twin Cities project	345	161	December-2014	North Rochester - SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV
MISO	SE Twin Cities project	345	161	March-2014	North La Crosse - SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV
MISO	G519 - Mesaba	230	115	July-2012	Swatara 230/115 kV
MISO	Brookings, SD - SE Twin Cities 345 kV	345	115	August-2013	Lyon County
MISO	Brookings, SD - SE Twin Cities 345 kV	345	115	January-2014	Lake Marion
MISO	Brookings, SD - SE Twin Cities 345 kV	345	230	March-2015	Hazel
MISO	Brookings, SD - SE Twin Cities 345 kV	230	115	June-2011	Morris
MISO	Brookings, SD - SE Twin Cities 345 kV	345	115	November-2013	Cedar Mountain
MISO	Hazleton - Salem	345	161	December-2012	Hazleton - Salem 345 kV line with a 2nd Salem 345/161 kV 448 MVA
MISO	Lewis Fields	161	115	June-2012	161 kV substation which taps the SwampFX - Coggon 115 kV line
MISO	Lewis Fields	161	115	December-2012	161 kV substation which taps the SwampFX - Coggon 115 kV line
MISO	Morgan Valley	345	161	June-2013	Build a 345 kV substation which taps the Arnold -Tiffin 345 kV line
MISO	Rising Substation - Increase Xfmr Rating	345	138	June-2012	Rising (Replacement)
MISO	Qualitech 345/138KV	345	138	June-2013	Qualitech Transformer and breakers
MISO	Cranberry Substation	500	138	June-2012	Cranberry Transformer #1
MISO	Cranberry Substation	500	138	June-2012	Cranberry Transformer #2
MISO	Grnd Mnd	161	115	December-2011	East Calamus (Replacement): Grnd Mnd 161-69kV 2nd Xfmr & 161kV loop
MISO	Hancock 230/120kV Transformer	230	120	December-2013	Hancock 230/120 kV
MISO	2nd Kewaunee 345-138 kV Transformer	345	138	June-2011	Kewaunee
MISO	Dresser 345/138kV Bank 3 addition	345	138	December-2011	Dresser
MISO	Petersburg	345	138	June-2012	(Replacement) 345/138kV E and W Autotransformers /345 kV breaker
MISO	Petersburg	345	138	June-2012	(Replacement) 345/138kV E and W Autotransformers /345 kV breaker
MISO	Stallings	345	138	June-2012	(Replacement) 345/138 kV Sub - Replace 560 MVA 345/138 kV transformer
MISO	South Bloomington -	345	138	December-2014	South Bloomington Install new 560 MVA 345 /138 Xfmr
MISO	North Mankato 115 kV project	345	115	June-2011	Helena
MISO	AEP Sullivan to DEM Brookston 765	765	345	August-2018	DEM Brookston
MISO	Ellendale to Big Stone South	345	230	December-2019	Ellendale 345/230
MISO	Big Stone South to Brookings	345	230	December-2017	Big Stone South 345/230
MISO	Big Stone South to Brookings	345	230	December-2017	Big Stone South 345/230
MISO	Meradosia to Pawnee	345	138	June-2015	Pawnee
MISO	Pana to Mt. Zion	345	138	June-2020	Mt. Zion
MISO	Thomas Hill - Adair - Ottumwa 345	345	161	June-2017	West Adair Substation
MISO	Nortwest Cape Area Substation	345	161	June-2016	Northwest Cape 345/161 kV
MISO	Green Acres Sub.- Transformer	345	138	June-2011	Green Acres

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
MISO	New 345kV Supply at Fargo Substation	345	138	December-2016	Fargo 345/138 kV
MISO	Murphy Second Transformer	345	138	June-2011	Murphy
MISO	Replace Bluemound TransformerT3	230	138	November-2011	Bluemound (Replacement)
MISO	Replace Bluemound TransformerT1	230	138	May-2012	Bluemound (Replacement)
MISO	Dubuque Co - Spring Green project	345	138	December-2020	Spring Green
MISO	Dubuque Co - Spring Green project	345	138	December-2020	Spring Green (Replacement)
MISO	Dubuque Co - Spring Green project	345	138	December-2020	Cardinal (Replacement)
MISO	Replace TR	345	138	December-2012	Sag clearance 2012 (Replacement)
MISO	Sub 39 Add 2nd 345-161 kV Xfmr	345	161	June-2014	Sub 39
MISO	Quincy Area 345/138 kV Substation	345	138	June-2017	Quincy Area
MISO	Kansas 2nd. Transformer	345	138	June-2017	Kansas Sub
MISO	Newton-Hutsonville-Merom Line	345	138	June-2018	Hutsonville Plant
MISO	Cass Lake -Nary-Helga -Bemidji 115	230	115	December-2012	Cass Lake 230 kV
MISO	Michigan Thumb Wind Zone	345	120	December-2013	Rapson (formerly Wyatt)
MISO	Michigan Thumb Wind Zone	345	120	December-2013	Rapson (formerly Wyatt) 345 kV
MISO	Michigan Thumb Wind Zone	345	120	December-2013	Rapson (formerly Wyatt) 345 kV
MISO	Michigan Thumb Wind Zone	345	120	December-2015	Sandusky 345 kV
MISO	G833-4_J022-3 Long Term Solution	345	138	June-2018	Barnhart
MISO	Webster - Hazleton 345 kV line	345	161	December-2018	Black Hawk
MRO-MAPP	Center 345/230 kV Transformer 1	345	230	October-2011	MPC 360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MRO-MAPP	Center 345/230 kV Transformer 2	345	230	October-2012	MPC 360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MRO-MAPP	Prairie 345/230 kV Transformer 1	345	230	October-2011	MPC 360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MRO-MAPP	Prairie 345/230 kV Transformer 2	345	230	October-2012	MPC 180 MVA RATING - MOVED FROM CENTER
MRO-MAPP	Appledorn	230	69	December-2011	WAPA
MRO-MAPP	Watford City	230	69	March-2012	WAPA replacing 115/69
MRO-MAPP	Elliot	115	69	December-2011	WAPA
MRO-MAPP	New Underwood	230	115	January-2014	WAPA Date not firm, replacement
MRO-MAPP	Belfield	345	230	January-2014	WAPA Date not firm, replacement
MRO-MAPP	Oahe	230	115	January-2014	WAPA Date not firm, replacement
MRO-MAPP	Bismarck	230	115	January-2015	WAPA Date not firm, replacement
MRO-Manitoba	Brandon Cornwallis	230	115	May-2013	120/160/176 MVA
MRO-Manitoba	Rockwood	230	115	November-2013	150/200/250 MVA
MRO-Manitoba	Riel	500	230	May-2014	720/960/1200 MVA; Associated with Bipole 3 / Conawapa project
MRO-Manitoba	Riel	500	230	May-2019	720/960/1200 MVA; Associated with 5th Manitoba - US tie project
MRO-Manitoba	Cornwallis	230	115	May-2013	
MRO-SaskPower	Tantallon Area Reinforcement	230	138	July-1905	Planned addition of a 300 MVA auto-transformer.
MRO-SaskPower	Tantallon Area Reinforcement	230	138	July-1905	Planned addition of a 300 MVA auto-transformer.

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
MRO-SaskPower	Peebles Area Reinforcement	230	138	July-1905	Planned addition of a 200 MVA auto-transformer.
MRO-SaskPower	Boundary Dam Area Reinforcement	230	138	July-1905	Planned addition of a 250 MVA auto-transformer.
MRO-SaskPower	Condie Area Reinforcement	230	138	July-1905	Conceptual addition of a 225 MVA auto-transformer.
MRO-SaskPower	Regina Area Reinforcement	230	138	July-1905	Conceptual addition of a 250 MVA auto-transformer.
NPCC-New England	2nd Deerfield Autotransformer Project	345	115	December-2012	Under Construction
NPCC-New England	NEEWS - GSRP Project - Agawam	345	115	December-2013	Under Construction
NPCC-New England	NEEWS - GSRP Project - Agawam	345	115	December-2013	Under Construction
NPCC-New England	NEEWS - GSRP Project N. Bloomfield	345	115	December-2013	Under Construction
NPCC-New England	NEEWS - CCRP Project - Frost Bridge	345	115	December-2016	Planned
NPCC-New England	MPRP - Albion Rd - Larabee Rd	345	115	August-2012	Planned
NPCC-New England	MPRP - South Gorham	345	115	May-2011	Under Construction
NPCC-New England	MPRP - Maguire Rd	345	115	September-2013	Planned
NPCC-New England	Lower South East Massachusetts	345	115	December-2012	Planned Upgrades
NPCC-New England	Greater Boston No, So. Central Woburn	345	115	December-2015	Concept
NPCC-New England	Greater Boston No, So. Central Sudbury	230	115	TBD	Concept
NPCC-New England	Greater Boston No, So. CentralWaltham	345	230	TBD	Concept
NPCC-New England	Central/Western MA Wachusett	345	115	December-2011	Planned Upgrades
NPCC-New England	Central/Western MA Bear Swamp	230	115	August-2013	Planned Updgrades
NPCC-New England	Auburn Area Transmission - Auburn	345	115	September-2012	Planned Updgrades
NPCC-New England	NEEWS Rhode Island	345	115	December-2013	Planned
NPCC-New England	Keene Rd	345	115	December-2011	Under Construction
NPCC-New England	Pittsfield/Greenfield - Northfield	345	115	December-2014	Proposed
NPCC-New York	South Perry	230	115	July-1905	
NPCC-New York	Watercure Road	345	230	July-1905	
NPCC-New York	Auburn New 345/115 kV Sub	345	115	July-1905	
NPCC-New York	ConEd's Line Y94 - Lovett	345	138	July-1905	
NPCC-New York	NYPA SR1-39 345kV Line - Rochester	345	115	July-1905	
NPCC-New York	NYPA NR-2 345kV Line - Rochester	345	115	July-1905	
NPCC-Ontario	Oshawa Area TS	500	230	December-2016	Conceptual
NPCC-Ontario	Milton TS	500	230	December-2016	Conceptual
NPCC-Québec	Bout-de l'Ile T11	735	315	November-2013	New 735 kV section in existing station
NPCC-Québec	Bout-de l'Ile T12	735	315	November-2013	New 735 kV section in existing station
NPCC-Québec	Pierre-Le Gardeur T1	315	120	November-2014	New Transformer Station
NPCC-Québec	Pierre-Le Gardeur T2	315	120	November-2014	New Transformer Station
NPCC-Québec	Saguenay 735/161 kV T4	735	161	September-2014	New transformer in existing station
NPCC-Québec	Arnaud 315/161 kV Transformer	315	161	September-2014	New transformer for Romaine Projects
NPCC-Québec	Romaine-1 Switching Station	315	161	September-2016	New transformer for Romaine Projects

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
PJM	North Fork	345	138	June-2014	Construct new 345/138 kV station in Marquis - Bixby 345 kV
PJM	Canton Central	345	138	June-2014	Install new 345/138 kV T-3
PJM	Baker	765	345	June-2015	Install new 765/345 kV T-300
PJM	Sullivan	765	345	June-2015	Install new 765/345 kV T-3
PJM	Cabot	500	138	September-2011	Install 4th transformer
PJM	Doubs	500	230	June-2011	Replace existing #3 bank
PJM	502 Junction	500	138	June-2013	
PJM	Welton Spring	765	500	TBD	New Substation
PJM	Kemptown	765	500	TBD	New Substation
PJM	Wylie Ridge	500	345	June-2011	Replace #5 Transformer
PJM	Wylie Ridge	500	345	June-2011	Replace #8 Transformer
PJM	Waugh Chapel	500	230	June-2011	Replace #1 500/230kV transformer
PJM	Fisk	345	138	July-2011	Install 1st auto at Fisk
PJM	Fisk	345	138	July-2011	Install 2nd auto at Fisk
PJM	Goodings Grove	345	138	June-2011	Install 3rd 345/138KV autotransformer
PJM	Plano	345	138	June-2013	Install 1st 345/138kV autotransformer
PJM	Bath	345	138	June-2015	Install 2nd 345/138kV transformer
PJM	Trebein	138	69	June-2015	Install 2nd 138/69kV transformer
PJM	West Milton	138	69	June-2015	Install 2nd 138/69kV transformer
PJM	West Milton	345	138	June-2015	Install 2nd 345/138kV transformer
PJM	Shelby	345	138	June-2014	Install 2nd 345/138kV transformer
PJM	Qualitech	345	138	June-2013	New Substation
PJM	Frances Creek	345	69	June-2014	New Transformer
PJM	Durbin	230	69	June-2017	New Substation
PJM	Curliss	138	69	June-2016	New Substation
PJM	Webster Road	138	69	May-2011	EKPC Initiated Project
PJM	Logans Ferry	345	138	March-2012	
PJM	Crescent	345	138	June-2014	Add 3rd 345/138 kV Autotransformer
PJM	Indian River	230	138	June-2011	Add a 3rd 230/138kV auto
PJM	Wattsville	138	69	December-2011	Add a 200 MVA transformer at
PJM	West Medina	138	69	June-2014	Add 90/120 MVA Transformer
PJM	Stacy	138	36	June-2012	New Sub - 75/100 MVA Transformer
PJM	Cranberry	500	138	June-2012	New Sub - 333/448/560 MVA transformer #1
PJM	Cranberry	500	138	June-2012	New Sub - 333/448/560 MVA transformer #2
PJM	Berlin Lake Area	138	69	June-2014	New Sub - 100/134MVA

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
PJM	Fulton	345	138	June-2014	New Sub - 180/240/336 MVA Transformer
PJM	Newton Falls	138	69	June-2016	Replace transformer #3 with 100/134 MVA transformer
PJM	Galion	138	69	June-2015	Replace transformer #3 with 100/134 MVA transformer
PJM	Hayes	345	138	June-2014	New Sub - 269/358/448 MVA transformer
PJM	Chamberlin	345	138	June-2016	Add 2nd transformer - 240/320/400 MVA
PJM	Broadview	138	69	June-2016	New 138 kV Sub - Add 100/134 MVA transformer #1
PJM	Broadview	138	69	June-2016	New 138 kV Sub - Add 100/134 MVA transformer #2
PJM	Henrietta	138	69	June-2011	New Sub - Add 100/134 MVA transformer
PJM	Center Point	500	230	June-2011	Install transformer at new substation
PJM	Plymouth Meeting	230	138	March-2011	Install 2nd Plymouth transformer
PJM	Eddystone	230	138	February-2011	
PJM	Heaton	230	138	December-2011	Install 2nd Heaton transformer
PJM	Chichester	230	138	December-2011	Install 2nd Chichester transformer
PJM	Burches Hill	500	230	June-2011	Add 2nd 1000 MVA 500/230kV Transformer
PJM	Burches Hill	500	230	December-2011	3rd Transformer
PJM	Brighton	500	230	June-2012	Replace Existing Transformer
PJM	Lackawanna	500	230	May-2014	In-service date changed; 750 MVA nameplate.
PJM	Everetts	230	115	June-2011	
PJM	Suffolk	500	230	May-2011	Second Transformer
PJM	Chancellor	500	115	June-2013	Second Transformer
PJM	Fredericksburg	230	115	June-2013	Second Transformer
PJM	Suffolk	500	230	June-2014	Third Transformer
PJM	North Anna	500	230	June-2014	Replace with a larger unit
PJM	Cannon Branch	230	115	June-2014	Replace with a larger unit
PJM	Fort Lee	230	115	December-2012	
PJM	Brambleton	500	230	June-2014	
PJM	Clover	500	230	June-2015	
PJM	Northern Neck	230	115	March-2011	
PJM	Oak Green	230	115	June-2015	
PJM	Staunton	230	115	June-2013	
PJM	Kitty Hawk	230	115	June-2015	Third Transformer
PJM	Roseland	500	230	June-2012	
SERC-E	Folkstone 230 kV Substation	230	115	June-2013	Under Construction - Install 1-200 MVA 230/115 kV transformer
SERC-E	Graniteville 230/115kV #3	230	115	December-2012	Under Construction - Add 3rd 336MVA transformer
SERC-E	Orangeburg	230	115	June-2012	Under Construction - New station under construction

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
SERC-E	Ritter 230/115kV	230	115	May-2011	Under Construction - Construction 336MVA Substation
SERC-E	West end 230 kV Transformers	230	115	June-2012	Under Construction - Replace existing 200 MVA transformers with new 300 MVA
SERC-E	CIP 230/115kV #2	230	115	May-2015	Planned - Add 2nd 336MVA transformer
SERC-E	Denny Terrace 230/115kV #3	230	115	December-2015	Planned - Add 3rd 336MVA transformer
SERC-E	Falls 230/115 kV Transformer	230	115	June-2016	Planned - Add 2nd 230/115 kV 300MVA transformer
SERC-E	Horse Gap to Watauga Transformer Relocation	230	99	December-2015	Planned - Move three single phase transformers from Horse Gap Substation to new Watauga 230 kV Substation.
SERC-E	Lake Murray 230/115kV #2	230	115	May-2013	Planned - Add 2nd 336 MVA transformer
SERC-E	Lake Murray 230/115kV #3	230	115	December-2015	Planned - Add 3rd 336MVA transformer
SERC-E	Mt. Olive 230 kV substation	230	115	December-2011	Planned - Install 1-200MVA 230/115 kV Transformer
SERC-E	Bucksville	230	115	June-2015	Conceptual - future substation
SERC-E	Fayetteville 230/115 kV Transformer	230	115	June-2014	Conceptual - Replace both 200 MVA transformer with 300 MVA banks.
SERC-E	Pomaria	230	99	June-2013	Conceptual - approval is pending
SERC-E	Purrysburg	230	115	November-2014	Conceptual - future substation
SERC-E	Richburg	230	99	July-2014	Conceptual - associated with nuclear integration
SERC-E	Sandy Run	230	115	May-2015	Conceptual - associated with nuclear integration
SERC-E	Selma 230/115 kV Transformer	230	115	June-2013	Conceptual - Add a 200 MVA Transformer Bank #2
SERC-E	St. George	230	115	May-2018	Conceptual - associated with nuclear integration
SERC-E	Varnville	230	115	July-2019	Conceptual - associated with nuclear integration
SERC-E	Wassamassaw	230	115	June-2017	Conceptual - future substation
SERC-E	Winnsboro	230	99	December-2013	Conceptual - associated with nuclear integration
SERC-N	Clay, MS – Addition	500	161	June-2012	Under Construction - Install four single phase 500-161 kV transformers
SERC-N	Guntersville, AL – Retirement	161	115	March-2011	Under Construction - Retire six, single phase 154-115-11.5 kV transformers
SERC-N	Guntersville, AL – Addition	161	115	March-2011	Under Construction - Install four, single phase 161-115-11.5 kV
SERC-N	Jackson, TN – Addition	500	161	June-2011	Under Construction - Install three single phase 500-161 kV transformers
SERC-N	West Ringgold, GA – Addition	230	115	June-2011	Under Construction - Install three phase 230-115-26 kV transformer
SERC-N	4th Middletown 345/138 – Addition	345	138	May-2012	Planned - Install 4th 345/138kV transformer at Middletown
SERC-N	Battlefield (NES) – Addition	161	99	June-2014	Planned - Add 161:69kV 200 MVA transformer to Battlefield substation
SERC-N	Montgomery, TN- Addition	500	161	June-2013	Planned - Install three, single phase 500-161 kV transformers
SERC-N	Green River #3 – Re-Rating	161	138	May-2020	Conceptual - Replace existing Green River #3 with MVA unit (Re-Rating)
SERC-SE	Bonaire	500	230	December-2012	Under Construction - Spare Single Phase Unit
SERC-SE	Carriere SW	230	115	May-2011	Under Construction - New Substation / Under Construction
SERC-SE	Dresden	500	230	May-2014	Under Construction - New Substation
SERC-SE	Newnan Primary	115	99	June-2011	Under Construction - Replace aged 115/46kV transformer
SERC-SE	silver Creek Interconnection	161	115	June-2011	Under Construction - Silver Creek Interconnection

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
SERC-SE	Silver Creek Interconnection	161	99	June-2011	Under Construction - Prentiss 161/69kV Substation
SERC-SE	Waynesboro Transformer Replacement	230	161	April-2011	Under Construction - Waynesboro 230/161kV Substation
SERC-SE	Autaugaville 500/230kV Auto	500	230	May-2013	Planned - Install new auto at Autaugaville 500 kV sub
SERC-SE	Boulevard	230	115	June-2015	Planned - ^new 300 MVA, 230/230-kV xfr
SERC-SE	Corn Crib 230/115 kV Project	230	115	June-2017	Planned - New 230/115-kV substation with a 300MVA bank
SERC-SE	County Line Rd Bank #2	230	115	May-2014	Planned - Install second auto at County Line Road
SERC-SE	Dorchester	230	115	June-2017	Planned - 2nd 400 MVA, 230/230-kV xfr
SERC-SE	East Social Circle	230	115	June-2014	Planned - Second transformer
SERC-SE	East Walton	500	230	June-2015	Planned - New substation
SERC-SE	East Waynesboro Substation	161	99	June-2013	Planned - East Waynesboro 230/69/ kV Substation (Addition)
SERC-SE	Factory Shoals 230/115kV transformer	230	115	May-2011	Planned - New 230/115-kV substation with a 300MVA bank (Addition)
SERC-SE	Farley 500/230kV #1 & #2 Autos	500	230	May-2019	Planned - Replace lowside equipment to achieve higher rating; No longer needed until 2019 (Re-Rating)
SERC-SE	Gainesville #2 230/115 kV Bank B	230	115	June-2018	Planned - Replace existing autobank with a 400 MVA autobank. (Re-Rating)
SERC-SE	Gainesville #2 230/115kV Bank C	230	115	June-2018	Planned - Replace existing autobank with a 400 MVA autobank. (Re-Rating)
SERC-SE	Greene County AutoBank – Addition	230	115	May-2013	Planned - Add 400MVA 230/115kV Autobank#2 at Plant Greene County
SERC-SE	Highland City	230	115	June-2015	Planned - 400 MVA Bank #1 (Addition)
SERC-SE	Highway 54	230	115	May-2016	Planned - New transformer (Addition)
SERC-SE	Holt TS - Tuscaloosa TS AutoBank	230	115	May-2011	Planned - Install 230/115kV AutoBank at Tuscaloosa TS (Addition)
SERC-SE	Hopewell	230	115	June-2015	Planned - - (Re-Rating)
SERC-SE	Laguna Beach	230	115	December-2012	Planned - 400 MVA Bank#2 (Addition)
SERC-SE	McIntosh	230	115	June-2013	Planned - replace 280 MVA, 230/230-kV xfr W/ 400 MVA xfr (Re-Rating)
SERC-SE	Meldrim	230	115	June-2011	Planned - new 300 MVA, 230/230-kV xfr (Addition)
SERC-SE	Meridian NE Bank #2	230	115	June-2013	Planned - Replace Transformer / On Order (Re-Rating)
SERC-SE	Meridian NE Bank 1	230	115	June-2013	Planned - Replace Transformer / On Order (Re-Rating)
SERC-SE	North Opelika Bank #2	230	115	May-2022	Planned - Install second auto at North Opelika;
SERC-SE	North Selma Bank #1	230	115	May-2014	Planned - Replace equipment to achieve higher rating (Re-Rating)
SERC-SE	Ocean Springs Bank #2	230	115	June-2014	Planned - Installing a parallel transformer in an existing station (Addition)
SERC-SE	Offerman Third 230/115 kV	230	115	June-2019	Planned - 140 MVA (Addition)
SERC-SE	Orange Grove	230	115	June-2020	Planned - New Substation (Addition)
SERC-SE	Plant McDon. Network Impvmts-P'tree	230	115	May-2013	Planned - Plant McDon. Network -P'tree Tfm. Removal (Retirement)
SERC-SE	Roswell	230	115	May-2018	Planned - Install a 230/115kV transformer in Roswell substation (Addition)
SERC-SE	Santa Rosa BK1	230	115	June-2015	Planned - 400 MVA Bank#1 (Addition)
SERC-SE	Santa Rosa BK2	230	115	June-2015	Planned - 400 MVA Bank#2 (Addition)
SERC-SE	Sharon Springs	230	115	June-2015	Planned - New Substation (Addition)
SERC-SE	Shoal River	230	115	June-2021	Planned - 400 MVA Bank#2 (Addition)

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
SERC-SE	Silverhill – Addition	230	115	June-2018	Planned - Install a third autobank (400MVA unit); Advanced to 2018
SERC-SE	Snellville 230/115 kV Transformer	230	115	May-2016	Planned - Replace 1600A low-side breaker with 2000A breaker (Re-Rating)
SERC-SE	South Bessemer AUTO #2	230	115	May-2022	Planned - Install second auto at South Bessemer;
SERC-SE	South Duncanville AutoBank – Addition	230	115	May-2015	Planned - Add 400MVA 230/115kV Autobank at South Duncanville
SERC-SE	South Enterprise Bank #1	230	115	May-2013	Planned - New auto at South Enterprise (Addition)
SERC-SE	South Hoy 161kV Transmission Project	161	99	June-2013	Planned - South Hoy 161/69 kV Substation (Addition)
SERC-SE	South Metro Atlanta Project Phase-3	230	115	June-2018	Planned - Install 1- 400 MVA Tfm. at McDonough Primary substation Add,
SERC-SE	Turf Club	230	115	May-2022	Planned - Add transformation at Turf Club (Addition)
SERC-SE	Union City	500	230	June-2013	Planned - Spare Single Phase Unit (Addition)
SERC-SE	Vimville	230	115	June-2014	Planned - New Substation (Addition)
SERC-SE	Waynesboro	230	115	June-2019	Planned - replace 280 MVA, 230/230-kV xfr W/ 400 MVA xfr (Re-Rating)
SERC-SE	Acadiana Area Improvement Project P1	230	138	June-2011	Under Construction - Add 500 MVA, 230-138 kV auto at Meaux (Addition)
SERC-SE	Baxter Wilson	500	115	June-2012	Under Construction - Add 2nd 500/115kV Auto (Addition)
SERC-SE	Holland Bottoms 500-115 – Addition	500	115	December-2011	Under Construction - Add a new 500-115 kV Substation in Little Rock
SERC-SE	McAdams	500	230	June-2011	Under Construction - Add 2nd 500/230kV Auto (Addition)
SERC-SE	Sarepta – Addition	345	115	June-2011	Under Construction - Construct a new 345-115 kV substation consisting of a 500 MVA auto. Cut station into EL Dorado to Longwood 345 kV line.
SERC-SE	Holland Bottoms 500-161	500	161	June-2012	Planned - Add a new 500-161 kV Substation in Little Rock (Addition)
SERC-SE	Ouachita Transmission Service	500	115	June-2012	Planned - Split Sterlington 115 kV bus & replace 500-115 auto #2 w/ 750 MVA (Re-Rating)
SERC-SE	S.Grenada	230	115	June-2012	Planned - Add 230/115kV Auto (Addition)
SERC-SE	Cypress	500	138	June-2018	Under Construction - Add 2nd auto at Cypress; rated 750 MVA (Addition)
SERC-SE	Grimes	345	138	June-2016	Under Construction - Add 3rd auto at Grimes; rated 525 MVA (Addition)
SERC-SE	Hartburg	500	230	June-2019	Under Construction - Add 2nd auto at Hartburg; rated 800 MVA (Addition)
SERC-SE	Senatobia Industrial	230	115	June-2015	Under Construction - Add 230/115kV Auto (Addition)
SERC-W	Acadiana Area Improvement Project P1	230	138	June-2011	Add 500 MVA, 230-138 kV auto at Meaux (Addition)
SERC-W	Baxter Wilson	500	115	June-2012	Add 2nd 500/115kV Auto (Addition)
SERC-W	Holland Bottoms 500-115	500	115	December-2011	Add a new 500-115 kV Substation in Little Rock (Addition)
SERC-W	McAdams	500	230	June-2011	Add 2nd 500/230kV Auto (Addition)
SERC-W	Sarepta	345	115	June-2011	Construct a new 345-115 kV substation consisting of a 500 MVA auto. Cut station into EL Dorado to Longwood 345 kV line (Addition)
SERC-W	Holland Bottoms 500-161	500	161	June-2012	Add a new 500-161 kV Substation in Little Rock (Addition)
SERC-W	Ouachita Transmission Service – ReRate	500	115	June-2012	Split Sterlington 115 kV bus and replace 500-115 auto #2 with 750 MVA
SERC-W	S.Grenada	230	115	June-2012	Add 230/115kV Auto (Addition)
SERC-W	Cypress	500	138	June-2018	Add 2nd auto at Cypress; rated 750 MVA (Addition)
SERC-W	Grimes	345	138	June-2016	Add 3rd auto at Grimes; rated 525 MVA (Addition)
SERC-W	Hartburg	500	230	June-2019	Add 2nd auto at Hartburg; rated 800 MVA (Addition)

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
SERC-W	Senatobia Industrial	230	115	June-2015	Add 230/115kV Auto (Addition)
SPP	Canaday T-4 Replacement	230	115	November-2010	Replaces existing 100 MVA T-4 with 336 MVA
SPP	Legacy	115	69	July-2011	Project in final design
SPP	Eagle Creek	115	69	August-2011	Project in final design
SPP	Segura Auto	230	138	August-2011	Autotransformer at Segura substation
SPP	Rork Auto	500	230	August-2011	Autotransformer at Richard substation
SPP	Cocodrie Auto #2	230	138	August-2011	Second Autotransformer at Cocodrie Substation
SPP	Johnston County	345	138	October-2011	
SPP	Tonnece Substation	345	161	December-2011	Planned Installation - Transformer enroute from factory
SPP	Hitchland Project	345	230	December-2011	Project in final design
SPP	Hitchland Project	230	115	December-2011	Project in final design
SPP	Gracemont	345	138	May-2012	
SPP	Acadiana Load Pocket Upgrade	230	138	June-2012	180 MVA base rating, Auto transformer
SPP	Arcadia	345	138	June-2012	
SPP	TUCO	345	230	June-2012	2nd autotransformer
SPP	Hitchland-Woodward Project	345	230	June-2012	2nd autotransformer
SPP	N Manhattan	230	115	June-2012	
SPP	Turk	345	138	July-2012	
SPP	Wells Auto #2	500	230	August-2012	Second Autotransformer at Wells Substation
SPP	Ochiltree	230	115	December-2012	
SPP	87th Street	345	115	December-2012	
SPP	Randall County	230	115	April-2013	2nd autotransformer
SPP	Canadian River	345	138	June-2013	
SPP	Cherry St. Intg.	230	115	June-2013	
SPP	Medicine Lodge 138/115kV	138	115	June-2013	Required by SPP
SPP	Rose Hill	345	138	June-2013	
SPP	Newhart	230	115	December-2013	
SPP	Plainview City	115	69	February-2014	
SPP	Shipe Road	345	161	June-2014	
SPP	Ogallala T-1 Relacement	230	115	June-2014	Replaces existing 187 MVA T-1 with 336 MVA
SPP	Greenwood	138	69	June-2014	
SPP	Woodward District EHV	345	138	June-2014	
SPP	Pleasant Hill	230	115	June-2014	
SPP	Auburn	230	115	June-2014	
SPP	Summit	345	115	June-2014	
SPP	Baldwin Creek	230	115	June-2014	

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
SPP	NASHUA	345	161	June-2015	
SPP	Stegall T-2 Addition	345	230	June-2015	Addition of second 400 MVA transformer at Stegall
SPP	Osage Creek	345	161	June-2016	
SPP	Ft. Smith	500	161	June-2017	
SPP	NW 68th & Holdrege	345	115	June-2020	Provide Additional Inlet Capacity For Reliability Purposes
WECC	Livock Phase Shifter	240	240	March-2012	
WECC	Heartland	500	240	March-2013	
WECC	Ponoka	240	138	March-2013	
WECC	Inisfail	240	138	March-2013	
WECC	Didsbury	240	138	March-2013	
WECC	Twin lakes	240	138	March-2013	
WECC	Nilrem	240	138	August-2012	
WECC	Pemukan	240	138	September-2012	
WECC	Lanfine	240	138	September-2012	
WECC	CoyoteLake	240	138	September-2012	
WECC	SS-65	240	138	December-2012	
WECC	Foothills	240	138	May-2014	
WECC	Chapel Rock	500	240	January-2014	
WECC	Fidler	240	138	December-2011	
WECC	Journault	240	138	May-2014	
WECC	Whitla	240	138	March-2014	
WECC	Bowmanton	240	138	March-2014	
WECC	Midpoint S/S	345	230	June-2011	Replace existing 500 MVA with new 700 MVA (expected schedule)
WECC	King S/S	230	138	June-2012	New Tie Bank (expected schedule)
WECC	Borah S/S	500	345	June-2016	New Tie Bank (expected schedule)
WECC	Thorne	120	60/12.5	June-2011	75 MVA
WECC	Selkirk Transformer (T4) Addition	500	230	September-2011	Selkirk substation in south interior region of BC
WECC	Harewood Transformers	230	138	March-2011	Harewood West Substation in Vancouver Island, BC
WECC	Okanagan Transmission Reinforcement	500	230	March-2011	Under Construction
WECC	ALMND 115	115	13.8	January-2012	
WECC	ALMND 115	115	14	January-2012	
WECC	ALMND 115	115	14	January-2012	
WECC	GRAY115	115	69	January-2012	
WECC	Century Receiving Station	287	138	TBD	Bank F
WECC	Century Receiving Station	287	138	TBD	Bank G

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
WECC	Alberhill System Project	500	115	June-2014	Includes installation of: (a) one 500/115kV substation; (b) two new 500kV line segments; (c) two new 560 MVA 500/115kV transformers; (d) a new 115kV subtransmission line; and (e) modifications to existing 115kV lines
WECC	Bayfront Substation Project	230	69	December-2012	This project includes installation of: (a) one 230/69kV substation to replace the existing 138/69kV South Bay substation; (b) two 224 MVA 230/69kV transformers; (c) loop in Miguel - Silvergate 230kV line into new substation; (d) transfer all existing 69kV lines from existing South Bay substation to the new substation; (e) re-configure existing 138kV lines to eliminate the need for South Bay 138kV bus
WECC	Sunrise Powerlink Project	500	230	June-2012	This project includes the following major installation of: (a) one new 500/230kV Suncrest Substation; (b) two new 1120 MVA 500/230kV transformers at Suncrest Substation; (c) one new 500kV line from Imperial Valley to Suncrest substation; (d) two new 230kV overhead/underground lines/cables from Suncrest to Sycamore Canyon substation
WECC	Harry Allen 500 /230 kV TX #3	525	230	December-2014	Conceptual
WECC	Harry Allen 345 /230 kV TX #3	345	230	June-2011	TX Delivered
WECC	Tortolita	500	138	May-2011	On schedule
WECC	Vail	345	138	December-2012	On schedule
WECC	AFTON	345	115	May-2015	Conceptual
WECC	North Gila	500	230	June-2014	Planned
WECC	Sun Valley	500	230	June-2014	Planned
WECC	3rd Kyrene 500/230kV Transformer	500	230	May-2012	Transformer
WECC	Pinal Central #1 Transformer	500	230	May-2014	Transformer
WECC	Pinal Central #2 Transformer	500	230	May-2014	Transformer
WECC	Abel 230/69kV Transformer	230	69	May-2011	Transformer
WECC	Rio Puerco	345	115	May-2011	Fully constructed waiting on outage coordination
WECC	Yatahey Transformer	345	115	December-2014	
WECC	Ojo Transformer	345	115	December-2013	
WECC	Davis 05	320	69	May-2011	Qy 2,150 MVA Replacements
WECC	Bouse	320	69	May-2011	Qy 1, 150 MVA
WECC	N. Havasu	320	69	May-2011	Qy 1, 100 MVA
WECC	Alderton Substation Transformer	230	115	October-2012	New 230/115-kV transformer at Alderton to feed Pierce County load growth.
WECC	Sedro Woolley Substation Transformer #2	230	115	October-2012	New 230/115-kV transformer at Sedro Woolley to feed load growth in Skagit County.
WECC	St. Clair Substation Transformer	230	115	October-2013	To feed load growth in Thurston County.
WECC	Lakeside Substation Transformer	230	115	October-2015	New transformer at Lakeside to feed load growth in King County.
WECC	Foss Corner Transformer	230	115	October-2018	New at Foss Corner to feed load growth in Kitsap County. (Conceptual).

Assessment Area	Transformer Project Name	Voltage High-Side (kV)	Voltage Low-Side (kV)	In-Service Date (Month-Year)	Description / Status
WECC	Canyon Substation	242	115	April-2011	New substation and interconnection to BPA.
WECC	Cowlitz Substation	242	115	July-2011	Replacement for existing bank 7 by a slightly larger transformer.
WECC	Moscow	230	115	September-2013	Upgrade
WECC	Horizon to Sunset	230	115	June-2012	Install a 230/115 kV, 320 MVA auto transformer at Horizon Substation
WECC	Bethel	500	230	June-2015	Installation of a new 500/230 kV transformer bank at PGE's Bethel Substation located in Salem, Oregon
WECC	Rocky Reach Auto Transformer #1	230	115	December-2016	Transformer Replacement Conceptual
WECC	Hooper Springs	138	115	December-2014	Construct 200 MVA Hooper Springs Substation adjacent to Three Mile Knoll (PAC) substation. Re-assess plan of service with least environmental impacts.
WECC	Redmond Transformer Addition	230	115	December-2011	Central Oregon Reinforcement project.300 MVA
WECC	Ponderosa Transformer Addition	500	230	October-2013	Central Oregon Reinforcement project. 700 MVA
WECC	Colstrip 230	230	100	October-2011	On order
WECC	Great Falls 230 Switchyard	230	100	November-2011	On order
WECC	South Butte	230	161	December-2012	In 2012 Budget
WECC	Great Falls	230	161	November-2011	100 MVA unit. Replaces existing 161/100 kV Rainbow unit. Includes relocation of interconnect with NWE from Rainbow 100 kV to Great Falls.
WECC	Bowdoin	161/230	115	March-2013	33 MVA unit to serve new substation tap between existing Richardson Coulee and Malta 161 kV substations for new oil load development.
WECC	Rapids Transformer	230	115	December-2013	Transformer at Rapids Switchyard connecting 230-kV bus to 115-kV bus
WECC	Fordham T1	230	115	September-2011	Under Construction
WECC	Fordham T2	230	115	September-2011	Under Construction
WECC	Horseshoe T1	230	115	May-2012	Under Construction
WECC	Horseshoe T2	230	115	May-2012	Under Construction
WECC	Timberline T2	230	115	May-2013	Planned
WECC	Boyd T2	230	115	May-2015	Planned
WECC	Weld PS 230/115 Transformer	230	115	May-2011	Replace esisting 230/115kV transformer at the Weld substation
WECC	Hopkins #2	230	115	June-2012	Replace the existing 100 MVA 230/115kV transformer
WECC	Poncha Junction 115/230 kV Auto	230	115	December-2012	New 280 MVA 230/115 kV 1 mile transmission line to utilize solar gen.
WECC	Flaming Gorge KY2B Transformer	230	138	October-2018	Replacement
WECC	Hayden KZ1A Transformer	230	138	October-2011	Replacement
WECC	Hayden KZ2A Transformer	230	138	October-2013	Replacement
WECC	Weld 230/115 kV	230	115	October-2012	Transformer Additions (Stage 04)
WECC	Ault 230/115 kV	230	115	October-2012	Transformer Additions (Stage 07)
WECC	Badwater	230	69	October-2013	Transformer Replacement
WECC	Cheyenne 2nd 230/115 kV	230	115	October-2014	Transformer Additions
WECC	Stegall KV1A	230	115	October-2015	Transformer and Breaker 882 Replacement

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