There are two different aspects to analyzing the bulk power system's reliability in the RNA: adequacy and security. 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, after adjustment of 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 CSPP 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. These criteria and a description of the nature of long-term bulk power system planning are described in detail in the CRPP Manual, and are briefly summarized below. In the event that market-based solutions do not materialize to meet a reliability need in a timely manner, the NYISO designates the Responsible TO or Responsible TOs to proceed with a regulated backstop solution in order to maintain system reliability. 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[189]. Under the CSPP, the NYISO also has an affirmative obligation to report historic congestion across the transmission system. In addition, the 2010 RNA is provided to the Independent Market Advisor for review and consideration of whether the market rules changes are necessary to address an identified failure, if any, in one of the NYISO's competitive markets. If market failure is identified as the reason for the lack of market-based solutions, the NYISO will explore

[189] The procedures for reviewing alternative regulated solutions for a reliability need are currently being discussed in NYPSC Case 07-E-1507.

appropriate changes in its market rules with its stakeholders and Independent Market Advisor. The CSPP does not substitute for the planning that each TO conducts to maintain the reliability of its own bulk and non-bulk power systems.

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 NYSPSC, 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**.**

Assumptions and Drivers

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 being 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 ten-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
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 2010 RNA Base Case model of the New York bulk power system includes the following new and proposed facilities and forecasts in the Gold Book:

- TO projects on non-bulk power facilities included in the FERC 715 Cases
- Facilities that have accepted their Attachment S cost allocations and are in service or under construction as of April 1, 2010
- Facilities that have obtained a PSC Certificate (or other regulatory approvals and SEQRA review) and an approved System Reliability Impact Study ("SRIS") and an executed contract with a credit-worthy entity
- Transmission upgrades related to any projects and facilities that are included in the RNA Base Case, as defined above
- TO plans identified in the 2010 Gold Book as firm plans
- Facility re-ratings and up-rates
- Scheduled retirements
- Special Case Resources (SCR) and the impacts of the NYSPSC EEPS Order, as developed and reviewed at the ESPWG
- External System Modeling

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**.**

Forecasts for peak load and energy as well as the impacts of programs such as EEPS and SCRs were developed for the ten-year study period. Projections for the installation and retirement of resources and transmission facilities are developed in conjunction with Market Participants and Transmission Owners and included in the Base Case. 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.

As part of the EEPS Proceeding, the NYSPSC directed a series of working groups composed of all interested parties to the proceeding to obtain information needed to further elaborate the goal. The NYSPSC issued an Order on June 23, 2008, setting short-term goals for programs to be implemented in the 2008-2011 period to begin the process of satisfying the NYSPSC's goal as applied to the entities over which it has jurisdiction. The NYSPSC anticipated that LIPA and NYPA and other state agencies would implement their own programs, including Energy Efficiency, improvements in building codes and new appliance standards.

The NYISO has been a party to the EEPS proceeding from its inception and is a member of the Evaluation Advisory Group, responsible for advising the DPS on the methods to be used to track program participation and measure the program costs, benefits, and impacts on electric energy usage. In conjunction with market participants in the Electric System Planning Working Group, the NYISO developed load forecasts for the potential impact of the EEPS over the ten-year planning period. The following factors were considered in developing the 2010 RNA Base Case forecast:

- NYSPSC-approved spending levels for the programs under its jurisdiction, including the Systems Benefit Charge and utility-specific programs
- Expectation of increased spending levels after 2011
- Expected realization rates, participation rates and timing of planned Energy Efficiency programs
- Degree to which Energy Efficiency is already included in the NYISO's econometric load forecast
- Impacts of new appliance efficiency standards, and building codes and standards
- Specific Energy Efficiency plans proposed by LIPA, NYPA and Consolidated Edison Company of New York, Inc. (Con Edison)

PRINCIPAL FINDINGS FOR THE 2011-2020 STUDY PERIOD

Reliability is defined and measured through the use of the concepts of adequacy and security. The NYISO first performs analysis of Transmission Security criteria violations. Then the NYISO assesses Transmission Adequacy and Resource Adequacy jointly with the use of General Electric's Multi Area Reliability Simulation (MARS) software package. This is done through the development of interface transfer limits and a Monte Carlo base simulation of the probabilistic outages of capacity and transmission outages.

Identifying reliability needs requires analysis and assessment of the transmission security of the BPTFs. The NYISO performed AC contingency analysis of the BPTFs to test for thermal and voltage violations using Siemens PTI PSS®MUST program using the AC Contingency Analysis activity. More detailed analysis was performed for critical contingency evaluation and transfer limit evaluation using the power-voltage (P-V) curve approach as described in NYISO Transmission Planning Guideline #2-0 and Operating Engineering Voltage Guideline (dated April 11, 2006) using the Siemens PTI PSS®E (Revision 30) software package. The impact of the status of critical generators on transfer limits was also quantified. Security for the BPTFs is and will be maintained by limiting power transfers. To assist in its assessment, the NYISO also reviewed many previously completed transmission security assessments.

Another 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, Transmission Owner Firm plans, and resource retirements. The calculated fault levels would be constant over the second five years because the method 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 will identify necessary mitigation solutions for the circuit breakers that are over their current interruption ratings and perform cost allocation of any identified upgrades during the applicable Class Year studies pursuant to Attachment S of the NYISO OATT.

The resultant load forecast, adjusted for the EEPS impact, has not resulted in any increased demands on the transmission system to meet capacity and energy needs in the NYCA system

Resource and transmission adequacy is evaluated for the entire ten-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.

The LOLE for the NYCA did not exceed 0.10 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 ten-year Study Period. No additional resources are forecasted to be required to maintain reliability at this time.

INSTALLED RESERVE MARGIN (IRM) STUDY

The NYISO performs a resource adequacy study to help the New York State Reliability Council determine the required Installed Reserve Margin for the upcoming capability year. This study specifies the margin required for the New York Balancing Authority area. The current level of the Installed Reserve Margin approved by FERC and the New York State Public Service Commission is 18.0 percent[190] for the 2010-2011 capability year. The NYISO conducts a study to determine the Locational Capacity Requirement[191] that must be fulfilled by load serving entities in the New York City and Long Island capacity zones. Reviewed by the NYISO's Operating Committee, that study determines the amount of capacity that must be electrically located within specific zones such as New York City and Long Island. The NYISO currently requires that a value of capacity equal to 79.6 percent of the New York City peak load be secured from within its zone and capacity totaling 104.9 percent of Long Island peak load be secured within that zone, for the 2010-2011 capability years. The NYISO also 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.

Presently, the New York State Reliability Council (NYSRC) Reliability Rules are implemented such that the electric system has the ability "to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled

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[190] New York Control Area Installed Capacity Requirements for the Period May 2010 through April 2011dated December 4, 2009. http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

[191] Locational Minimum Installed Capacity Requirements Study - Covering the New York Control Area for the 2010 – 2011 Capability Year. http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

outages of system elements." Compliance is evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be no more than an average of 0.1 days per year. This evaluation gives allowance for NYS Transmission System transfer capability documented in NYSRC Rules, Installed Reserve Margin, and Locational Capacity Requirements reports. Currently deliverability concerns in the IRM study are captured in the evaluation and there are none identified needing mitigation. A multi area reliability simulation capturing the significant limitations of the NYS Transmission System is performed every year to demonstrate compliance.

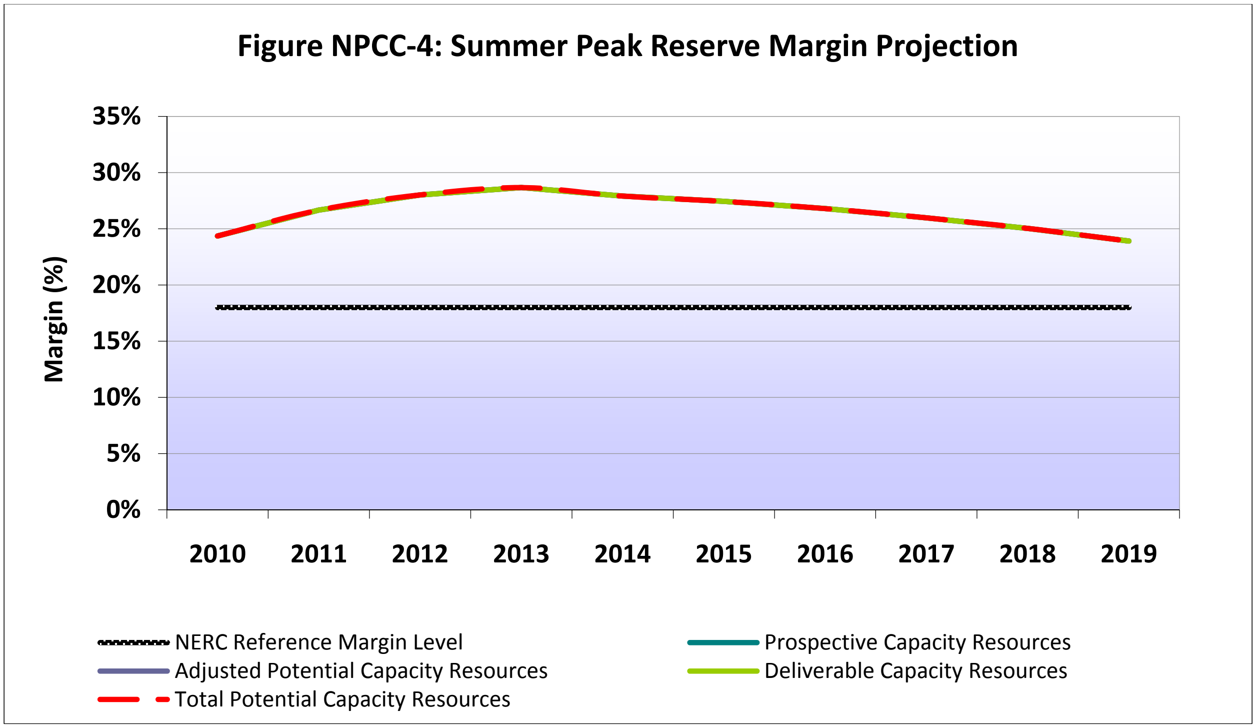
Based upon the IRM and Locational Capacity Requirements, the NYISO conducts semi-annual, monthly and spot Installed Capacity (ICAP) auctions. Using the forecast load for 2010 and the 18.0 percent IRM, the NYISO calculated the ICAP requirement as 38,970 MW. Last year the IRM requirement was 16.5 percent. In addition to the generation resources within the New York Balancing Authority area, generation resources external to New York can also participate in the NYISO ICAP market. An external ICAP supplier must declare that the amount of generation that is accepted as ICAP in New York will not be sold elsewhere. The external Balancing Authority in which the supplier is located has to agree that the supplier will not be recalled or curtailed to support its own loads; or will treat the supplier using the same pro rata curtailment priority for resources within its Control Area. The energy that has been accepted as ICAP in New York must be demonstrated to be deliverable to the New York border. The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to New York. Resources within the New York Balancing Authority area that provide firm capacity to an entity external to New York are not qualified to participate in the NYISO ICAP market.

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[192] showed that the New York Control 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.

[192] 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



The NYISO performs transient dynamics and voltage studies. There are no stability issues anticipated that could affect reliability during the 2010 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. Load and capacity assessment are also discussed for forecasted peak conditions.

Environmental Concerns

New York has a long history in the active development of environmental regulations that govern the permitting, construction and operation of power generation and transmission facilities. New York State's plan is mapped out by the New York State Department of Environmental Conservation (NYSDEC) in the annual publication of its regulatory agenda[193]. The U.S. Environmental Protection Agency (USEPA)

[193] http://www.dos.state.ny.us/info/register/2010/jan6/pdfs/regagenda.pdf

also publishes a similar report on its regulatory agenda[194]. The environmental initiatives that may affect generation resources in New York may be driven by either or both state or federal programs.

Reasonably Available Control Technology for Oxides of Nitrogen (NOxRACT)

NYSDEC has proposed 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 NY. NYSDEC is seeking to reduce emissions from the affected generators by 50%. 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.

Best Available Retrofit Technology (BART)

NYSDEC 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. The regulation is necessary for New York State to come into compliance with provisions of the federal Clean Air Act that are designed to improve visibility in National Parks. The compliance deadline has been set as January 2014.

Maximum Achievable Control Technology (MACT)

The U.S. EPA is required to develop rules to limit emissions of certain substances, which are classified as toxic. USEPA is scheduled to release a proposed rule March 2011. The rule will establish limits for Particulate Matter (PM), Hydrogen Chloride (HCl), Mercury (Hg), Carbon Monoxide (CO), and Dioxin and Furans. These limits will apply to coal fired generators and may apply to electric generators that are fueled by heavy oil. The anticipated compliance date is November 2014.

Best Available Technology (BTA)

NYSDEC is currently seeking comment on its policy documents "Best Technology Available (BTA) for Cooling Water Intake Structures. The program goals call for the use of wet closed cycle cooling systems at affected existing generating facilities. The policy is applied at the time of renewal for the existing State Pollution Discharge Elimination System Permit.

These environmental initiatives are in various stages of development. The NYISO will use the best available information to determine the impact that these initiatives may or may not have on the reliability of the New York Control Area. Scenarios are being developed for use in the current 2010 RNA study being conducted now. Results will be published in the 2010 RNA report.

194 http://www.reginfo.gov/public/do/eAgendaMain;jsessionid=9f8e890430d77ed37246b4ab417e9961cfca348ec55b.e34ObxiKbN0Sci0RbxaSc3qRc3n0n6jAmljGr5XDqQLvpAe?operation=OPERATION_GET_AGENCY_RULE_LIST&currentPub=true&agencyCd=2000&Image58.x=36&Image58.y=15.

FUEL SUPPLY

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 older steam units located in load pockets and would impact reliability needs in multiple ways if they were to retire and 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 NYSIO categorizes generation capacity fuel types into three supply risks: Low, Moderate and High.

The greatest risk to fuel supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is approximately 9,000 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%, 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% derate factor. This derate factor represents a severe scenario case for drought or low water level.

Risk Mitigation

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.

Region Description

The New York Control Area is a single state ISO (NYISO) formed as the successor to the New York Power Pool – a consortium of the eight investor-owned utilities, in 1999. The NYISO manages the New York State transmission grid encompassing approximately 10,892 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.2 million New Yorkers. New York experiences its peak load in the summer period with the current peak load of 33,939 MWs in the summer of 2006. (http://www.nyiso.com).

ONTARIO SUBREGION

INTRODUCTION

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 average annual demand growth rate for Ontario is revised upward by 0.5% compared to what was reported last year. The Reserve Margin is projected to be 27.7% in 2011, dropping to 20.0% in 2015 and then increasing to 27.8% in 2019, all above the target levels.

DEMAND

This year's demand forecast net of conservation has an average annual growth rate of -0.4% over the period 2010-2019 compared to last year's average growth of -0.9% for the 2009-2018 timeframe. The average growth rate is higher this year as the recessionary year of 2009 is no longer part of the calculation. However, the negative demand growth continues as a result of increased conservation efforts, growth in embedded (distributed) generation and restructuring in the energy-intense industrial sector.

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 a slow economic recovery over the near term (2010-2011) before returning to its long-term growth trend based on demographic factors. Electricity demand is expected to lag the general economic recovery as structural changes take place in Ontario's economy. Conservation savings and the growth in embedded generation are expected to more than offset the growth in demand from increased population and economic expansion. Reliability analysis is based on this demand forecast.

The forecast of Ontario peak demand is the system peak demand and therefore represents the coincident peak demand of Ontario's ten main sub-areas. All analysis is done on the system peak demand.

The Ontario Power Authority (OPA) is responsible for coordinating conservation programs throughout the province. To date, there are a number of initiatives that will reduce electricity demand. These programs range from lighting and appliance replacement to building retrofits targeted towards the residential, commercial, and industrial sectors. Measurement and verification is the responsibility of the OPA as part of their mandate. Incremental conservation savings are expected to reach 3,300 MW over the forecast horizon.

Demand response within Ontario includes a number of different programs. Some wholesale customers within the province bid their load into the market and are responsive to price through IESO dispatch instructions. Other customers have been contracted by the OPA to provide Demand Response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and currently amounts to slightly more than 1,250 MW in total, of which 56% is included for seasonal capacity planning purposes, with half of the included amount categorized as interruptible. This amount is expected to grow over time as more load is contracted to respond to tight supply conditions. By the end of the forecast, the interruptible component is expected to grow by more than 525 MW. The impacts of these initiatives are reflected in the 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. The IESO also reviews the reliability of the system prior to the impact of planned conservation savings. Although the IESO did not explicitly look at alternate economic scenarios, the pre-conservation results are considered as a surrogate for the potential to return to previous growth rates.

GENERATION

For summer 2010, the total existing Certain capacity resources connected to the IESO controlled grid is 32,115 MW. The existing Other capacity amounts to 4,849 MW which includes on-peak resource deratings, planned outages and transmission-limited resources. The Inoperable capacity is 28 MW. A net capacity increase of about 1,00 MW is recorded since last summer. Most of the increase was from gas-fired generation with smaller additions from hydroelectric and biomass generation.

The installed capacity of the existing resources will decrease by about 2,000 MW in October 2010 with the de-registration of four coal-fired units at Lambton and Nanticoke. The remaining coal generation capacity, amounting to 4,400 MW, will cease burning coal by the end of 2014. Besides coal shutdown, additional decreases are attributed to the anticipated retirement or refurbishment of several nuclear units. Therefore, the existing capacity may decrease significantly at the end 2014 and onward to 2019. To manage the possible reduction in existing resources, 12,500 MW of future capacity resources, as well as 9,000 MW of conceptual capacity resources, are scheduled to be in service by 2019, depending on unit refurbishment or retirement plans. With the estimated contribution of conservation programs administered by the OPA, and forecast increases in distributed generation, the combination of Existing, Future and Conceptual resources are expected to satisfy target reserve margins, ranging from 17.0% to 18.9%, throughout the forecast period.

As of spring 2010, the existing installed capacity of wind generation resources on the IESO controlled grid was 1,084 MW. Thirteen 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 forty percent of installed for the summer peak and five percent of installed for the winter peak. These values are based on historical modeled photovoltaic output data at the time of summer and winter peaks.

No derate is forecast for biomass generation. It is assumed that the full installed capacity will be available at the time of the peak.

Assumptions related to amounts and types of Conceptual capacity resources are from the Ontario Power Authority. Established in 2005, the OPA is the electricity system planner for the province of Ontario.

The OPA's statutory objects require it to, among other things, ensure adequate, reliable and secure electricity supply and resources in Ontario and to conduct independent planning for electricity conservation, demand management, renewable and other generation, and transmission.

In September 2009 the provincial government passed the Green Energy and Green Economy Act (GEGEA) providing a comprehensive framework for developing renewable energy generation. This framework includes a feed-in tariff (FIT) program and provisions that will facilitate the implementation of the necessary transmission and distribution infrastructure to support those renewable projects.

Approximately 3,300 MW of Conceptual renewable resources are expected to come on-line by 2019. This amount includes resources that are embedded and grid-connected. This is made up by about 2,400 MW of wind, 700 MW of solar, 80 MW of hydroelectric and 25 MW of biomass.

Generation resources identified for reliability analysis include (a) those which are currently in operation, (b) those which are not currently in operation but are anticipated to enter service in the future further to an executed financial contract with the Ontario Power Authority or further to an existing or anticipated government directive and (c) those Conceptual sources 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 Ontario Power Authority on an ongoing basis as part of its regular planning activities. Sensitivities and/or revisions to projections of Conceptual resources take place within that ongoing planning process.

Conceptual resources have been identified and categorized consistent with the planning assumptions of the Ontario Power Authority. These planning assumptions reflect anticipated take-up of renewable energy procurement initiatives administrated by the Ontario Power Authority, sequencing of associated transmission developments, projections around nuclear refurbishments and other projections.

Capacity Transactions on Peak

No Firm, Expected or Provisional imports into Ontario or exports to other Regions are considered in this *2010 Long-Term Reliability Assessment*. The IESO has agreements in place with neighbouring jurisdictions in NPCC, RFC and MRO for emergency imports and reserve sharing, should they be required in day-to-day operations.

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 1,200 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 total approximately 8,100 MW.

The existing Bruce special protection system (SPS) is also to 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.

Since the current version of the Bruce SPS has now been in-service for over 16 years and some of the equipment has been superseded by more advanced technology, a project has been initiated by Hydro One Networks to replace the existing facilities. The replacement SPS is scheduled to be in-service by late-2012.

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 bus bar, and another 350 MVAR SVC is to be installed at Detweiler TS, connected to the 230 kV bus bar. These SVCs are required to provide dynamic reactive support following a critical contingency involving any of the 500 kV circuits between the Bruce complex and Milton SS.

In 2010, approximately 1,500 MVAR of 230 kV-connected shunt capacitor banks are to be installed at Nanticoke SS and Middleport TS. Although these capacitor banks are required primarily to provide reactive support following the anticipated shut-down at the end of 2014 of the generating facilities at Nanticoke GS, they are also an integral component of the measures required during the interim period prior to the completion of the new Bruce to Milton 500 kV line. With Units 1 & 2 at the Bruce complex scheduled to return to service late 2011 or early 2012, there will be periods during 2011 and 2012 when either seven or eight Bruce units will be available for service. During these periods of high loading on the existing transmission circuits, reactive power management plays a significant role in reducing generation constraints. During the interim period, prior to the new line being completed, the new shunt capacitor banks will allow as much of the reactive capability from each of the operational units at Nanticoke SS to remain available for post-contingency voltage support. Once the new line is in service, the shunt capacitor banks together with new SVCs are required to support the post-contingency transfers without the need for generation rejection.

In late 2010, installation of series capacitors is to be completed at Nobel TS, the approximate mid-point of the two 500 kV circuits between Hanmer TS (Sudbury) and Essa TS (Barrie). To complement these series capacitors, the installation of a 300/-100 MVAR SVC will be completed at Porcupine TS (Timmins) and a 200/-100 MVAR SVC is to be installed at Kirkland Lake TS. Together, these facilities will increase the transfer capability of the Flow-South Interface from 1,300 MW to approximately 2,100 MW. This increase will be sufficient to relieve the existing congestion on this interface, while also accommodating the additional output from the proposed expansion of the four existing hydroelectric stations on the Lower Mattagami River (approximately 450 MW) together with other committed renewable energy developments in northern Ontario.

Phase angle regulators (PARs) are installed on the Ontario-Michigan interconnection at Lambton TS, representing two of the four interconnections with Michigan, but are not currently operational until completion of agreements between the IESO, the MISO, Hydro One and International Transmission Company. The expected in service date is not known at this time. The operation of these PARs along with the PAR on the Ontario-Michigan interconnection near Windsor will control flows to a limited extent, and assist in the control of Lake Erie Circulation.

The capability to control flows on the Ontario-Michigan interconnection between Scott TS and Bunce Creek is unavailable. The PAR installed at Bunce Creek in Michigan has failed and is scheduled for replacement by the beginning of Q3 in 2010. Without all four PARs in-service, there is no capability to control Lake Erie Circulation.

In October 2009, Ontario launched a feed-in tariff (FIT) program which generated interest in more than 9,000 MW of renewable generation – predominantly wind and solar generation - during the first two months of the program. Contracts for FIT program projects totaling 2,000 MW were executed based on existing transmission capability. This includes transmission and distribution connected projects. There are limitations to the existing transmission system that limits the amount and location of generation that can be connected. Some are regionally related while others are related to specific connection limitations associated with equipment capability or short circuit capability. These limitations vary over different parts of the system.

A number of major transmission reinforcement projects are being considered to enable greater renewable generation development across Ontario. The need and timing of these projects are driven by the uptake and location of the generation projects that have applied under the FIT program or that have been procured through other means. Examples of areas where bulk transmission options are being considered by the OPA include west of London and northwestern Ontario.

The completion of new gas-fired generating facilities in the Sarnia and Windsor area has added approximately 1,900 MW of capacity in the area and resulted in constraints on the transmission system west of London. Two coal-fired units in this area, at Lambton, are planned to be deregistered in 2010 as part of Ontario's plan to phase-out coal-fired generation. Development of significant amounts of renewable generation west of London, driven by the FIT program, will require transmission reinforcement west of London. The FIT program received a significant number of applications for renewable generation in this area. Depending on the total amount of new generating capacity expected to be incorporated, these transmission facilities, including associated auto-transformers, would be designed for operation at either 230 kV or 500 kV.

The northwest system is a sub-system connected to the rest of Ontario by the double circuit 230 kV East-West Tie. The region has significant amounts of hydroelectric generation and low water conditions can have a negative impact on the ability to serve the area load. 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 conditions, additional generation or increased westbound transfer capability into this region is required. This is one of the needs for this area. At other times, there can be periods of significant excess of supply over local demand. The FIT program has received significant renewable generation interest in this region. Additionally, demand in this area has reduced by 350 MW and 2.5 TWh over the past few years. However, there is limited transmission capability to transfer power eastbound out of this region, thus additional transfer capability is required. Solutions to meeting both needs are being assessed.

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 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. In the northwest, the supply security constraint may be addressed in the interim through imports, generation procurements, demand response, or post-contingency load rejection in the interim until the appropriate solutions are in service.

In addition to the bulk transmission projects, there are plans, under various stages of development, to address the concerns identified in some of the large load centers regarding supply security and the ability to restore the supply following an interruption. In Windsor-Essex, a new transformer station and a new 230 kV line are being proposed to address inadequate supply capability and security. For the Kitchener-Waterloo-Cambridge-Guelph Region the on-going needs would be addressed through a multi-staged solution that includes conservation, local generation and transmission. In the case of the Northern York Region, demand management and the addition of Holland TS in 2009 have helped to relieve some of the growing supply constraint in the Region in the interim. New gas-fired generation is expected to be in service in 2012 to address inadequate supply to this area. The installation of generation capacity in the south-western portion of the Greater Toronto Area is required to maintain reliability at the local level, while providing for the required system level security as coal-fired generation is decommissioned in accordance with government policy by 2014.

Five units at Pickering Nuclear Generating Station (NGS) are anticipated to reach end of life by 2015 and all units are anticipated to reach end of life by 2016. Ontario Power Generation announced early this year its investment plan for continued safe and reliable performance of its Pickering B station for approximately 10 years. Currently, Pickering NGS connects directly to the 230 kV system at Cherrywood TS in the east GTA. The retirement of Pickering NGS would require a new 500 kV/230 kV transformer station in the Oshawa area to reliably supply loads in the region.

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.

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. Current Ontario government directives call for the amount of planned nuclear capacity to be limited to 14,000 MW over the next 20 years. To meet this objective, the majority of nuclear units will need to be refurbished, or replaced through new-build projects. Post-2015, decisions and timelines regarding the retirement or refurbishment of existing nuclear units will require a sophisticated outage management program to ensure an adequate level of resources and operational flexibility. As discussed in the Transmission section above, careful management of the transmission system with respect to outages and new transmission capability will also be required. For the time being, plans for new nuclear have been suspended.

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. Anticipated future and Conceptual supply resources and a lower demand forecast (due to conservation targets, increased distributed generation, and a restructuring economy) has Ontario well positioned for the phase-out of approximately 6,400 MW of coal-fired generation by the end of 2014. This has enabled the Ontario government to implement greenhouse gas emissions limits for coal-powered generation starting last year. Emission targets are 11.5 megatons for the next four years.

The integration of variable resources (wind, solar, etc) is a major priority as Ontario moves towards a higher penetration of renewable resources. Wind capacity connected to the bulk power transmission system is expected to exceed 2,300 MW by 2011. Similar to other jurisdictions, the IESO has identified that at higher wind penetration levels, heightened attention would be required for the system to be able to handle the variability of wind generation. Centralized wind forecasting is an initiative designed to allow for better forecasting of wind production to ensure that a more accurate unit commitment occurs. Pilot implementation is expected to commence by the end of 2010.

The expansion of renewable generation within Ontario's distribution systems is expected to increase significantly over the next ten years. The OPA is managing contracts for over 6,600 MW of renewable generation connected to the distribution system. 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 SVC's to replace this loss 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, to increase visibility of the real-time output of distributed generation in an effective manner.

Last year Ontario began 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, plans are underway to provide incentives to grid-connected and large embedded intermittent generators (expected from the FIT program) when they respond to economic dispatches under 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 less than 3% of total resources. At these levels, any failure to respond does not pose any significant concern for reliability. Demand measures are grouped into two categories, price sensitive and voluntary. IESO considers only price sensitive demand for adequacy assessment purposes and to be dispatched, they have to bid into the market, like other resources.

Reliability Assessment Analysis

IESO reliability assessments include multi-area resource adequacy modeling and transmission adequacy assessments that are conducted to determine the deliverability of resources to load. Assessment criteria and processes are described in the documents "Methodology to Perform Long-Term Assessments"[195] and "Ontario Resource and Transmission Assessment Criteria"[196].

From these assessments, two major reports are periodically published by the IESO:

1. 18-Month Outlook
2. Ontario Reliability Outlook

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[195] http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

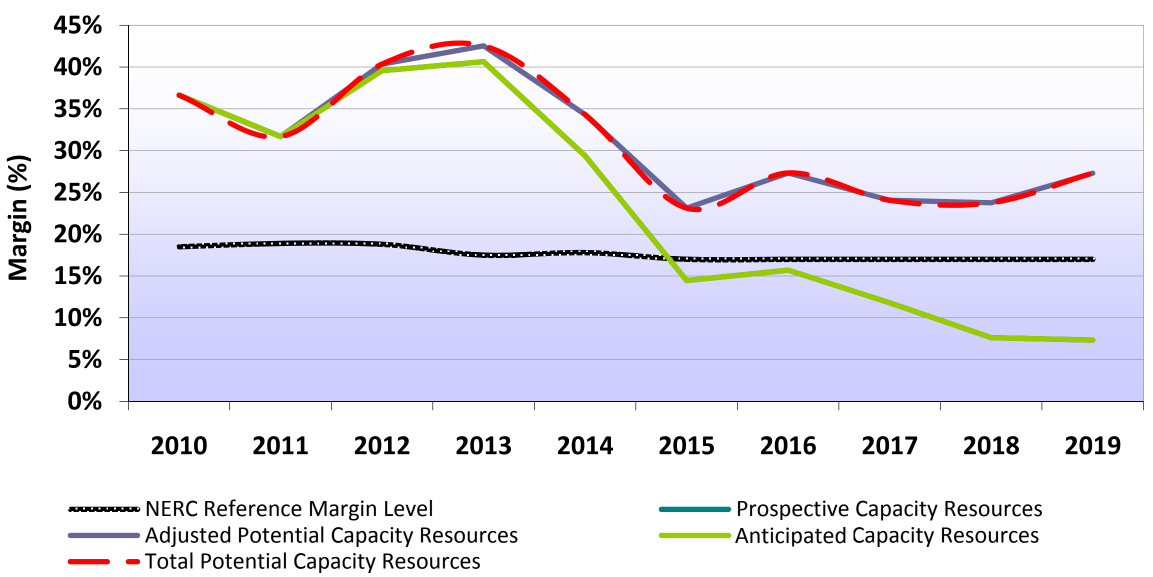
[196] http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

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.

At least once a year, the IESO investigates the adequacy of the Ontario system for the next five years. The key messages stemming from this adequacy assessment are published in the "Ontario Reserve Margin Requirements".[197]

The IESO determines required reserve levels based on probabilistic methods deemed by NPCC to be acceptable for meeting Regional loss of loss expectation (LOLE) criteria. The target reserve margin levels range from 18.5% in 2010 to 17.8% in 2014. The OPA target reserve margin of 17% is applied beyond 2014 (see Figure NPCC-5)

Figure NPCC-5: Summer Peak Reserve Margin Projections



Each year, in compliance with NPCC and Ontario requirements, the IESO performs a 5-year LOLE analysis to determine the resource adequacy of Ontario. Every third year, a comprehensive study is conducted, with annual interim reviews between major studies. In addition, the IESO participates with other members of NPCC in Regional studies that assess the Regional long range adequacy and interconnection benefits between Balancing Authorities in NPCC. Similar transmission assessments are carried out; these are referenced below.

[197] http://www.ieso.ca/imoweb/pubs/marketReports/Ontario-Reserve-Margin-Requirements-2010-2014.pdf

The reserve requirements are met solely with existing, future and Conceptual resources that are internal to Ontario. The total installed capacity, both generation and Demand Response resources, that were assumed at the time of summer 2010 is 36,372 MW. During supply shortage conditions, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC and MRO contain contractual provisions for emergency imports directly by the IESO. Ontario, also, has access to Regional reserve sharing for operating reserve activation under contingency situations.

Projected reserve margin requirements are determined on the basis of the IESO's requirement for Ontario self-sufficiency. At least once a year the IESO assesses resource requirements for the next five years (short-term period). In association with the OPA, reserve margin requirements for the long term (years 6-10) are determined and resource plans are developed, as part of the integrated planning process. Transmission assessments for specific projects are conducted on an as needed basis, as far into the future as necessary, recognizing the long lead time for significant transmission facility development. In addition, a review of the transmission system over the next 5-year period is conducted annually to ensure continued adherence with NPCC Criteria. A comprehensive review is also required to be undertaken at least every five years. These reviews are useful in identifying possible future deficiencies in the transmission system.

IESO and the 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.

IESO assessments of resource adequacy recognize the supply limitations associated with uncertain and 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. Uncertain resources, such as wind, are considered using a statistical approach which conservatively combines simulated and historical data to arrive at expected levels of 'certain' capability.

Ontario's Green Energy and Green Economy Act is resulting in the large scale development of renewable energy projects and implementation of conservation. The IESO continues to track the progress of renewable energy projects, and is streamlining its processes to incorporate additional renewable projects in the future. For assessment purposes, variable generation such as wind and solar are treated as capacity resources with discounted capacity values based on historical output at the time of seasonal peak demand (see Generation section for detailed description).

Demand response programs in Ontario are treated as a supply resource with discounted capacities associated with the unique characteristics of each program (*e.g.* voluntary/firm contracts). The OPA manages contracts for the majority of the Demand Response programs scheduled to come into service over the forecast timeframe. Programs with firm contracts to reduce demand during periods of high demand/tight supply are expected to provide a reliable and verifiable supply resource.

A number of major unit refurbishment or retirement decisions are expected to occur in Ontario throughout the assessment timeframe. Expected unit retirements are approximately 6,400 MW of coal-fired resources across four facilities and 15 units (by the end of the year 2014). In addition, as described in the Operational Issues section, a number of existing nuclear units are scheduled for retirement, or alternatively, refurbishment in the latter half of the next decade.

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 transmission that would be required to integrate all of the above-mentioned resources. Other options include the potential for firm purchases from outside of Ontario, expanding capability at existing gas-fired stations, continuation of capability at existing gas-fired stations that would otherwise be retired, developing greater coordination and flexibility related to nuclear refurbishment outages and converting existing coal stations to alternate fuels. Mitigation of reliability concerns is to be supported through ongoing monitoring, assessment, measurement, verification and regular updates.

So far, the following measures have been taken to mitigate the reliability concern from the retirement of coal units:

- An addition of about 3,800 MW of new gas-fired generation (combined cycle and combined heat and power)
- A capacity increase of about 100 MW at Beck hydroelectric station
- An addition of 1,200 MW of renewable generation

The following large generation will be added before 2015:

- 1,500 MW from two refurbished nuclear units
- 2,200 MW gas-fired generation (simple cycle and combined cycle)

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 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 includes the major electricity sector players including the provincial government's Ministry of Energy. The EPTF oversees an emergency management team, the Crisis Management Support Team (CMST), to manage the crisis and mitigate the impact on public health and safety due to an extended electricity system emergency. Annually Ontario runs a program of Reliability and Emergency Management workshops including table top drills. Additionally major integrated exercises are staged in which both the operational response and emergency management infrastructure is activated. The CMST also performs regular test activations.

During the nine day capacity and energy emergency that followed the August 2003 blackout, the CMST managed the emergency via thirty-one conference call meetings and were instrumental in producing media messages, facilitating the government's appeal and direction for reduced demand and obtaining of environmental variances for additional supply.

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 geomagnetic 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 in the affected areas would not cause the limit for the tie-line inrush to be exceeded.

Interruption of the transfers across one of the interconnection interfaces with Ontario would be automatically compensated by changes in the transfers across the remaining interfaces and by adjustment of the output from the generating facilities within Ontario. The subsequent change in the combined transfer across the remaining interfaces would remain within the tie-line inrush and outrush limits.

In 2009, the IESO conducted an Interim Review of Transmission Adequacy which assessed the IESO controlled grid's conformance with the NERC TPL-001 – 4 standards and NPCC's more stringent planning criteria: NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System. The Ontario power system, including the proposed generation and transmission changes up to 2014, is in conformance with the applicable NPCC criteria and NERC standards, with no exceptions. The proposed changes and additions to the existing power system in Ontario will not adversely affect the reliability of the Eastern Interconnection.

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

The IESO requires a 10% margin from the knee of the PV curve to be maintained for pre-contingency voltage stability and a margin of 5% to be maintained for post-contingency stability. All analysis is performed with system loads modelled as 'constant MVA'.

The IESO is developing an on-line limit derivation tool to maximize transmission capability in the operating time frame. This tool is planned to be implemented in stages over the next three years. For 2010, the initial stage of software development has been completed, and business processes have been revised to introduce the initial stages of tool capability.

By the end of 2010, households and small businesses in Ontario, totalling 4.5 million consumers, will have smart meters installed on their premises. As of December 2009, 3.4 million smart meters had been installed, with 350,000 customers paying time-of-use (TOU) rates. The implementation of TOU rates will ramp up significantly over the coming year. Early indications suggest that as consumers become more familiar with the new rate structure, load shifting away from peak and mid-peak hours will start to take place.

In 2008 the IESO initiated the Ontario Smart Grid Forum, a broad-based industry working group focused on developing a vision for a provincial smart grid that will provide consumers with more efficient, responsive and cost effective electricity service. A report on the key findings and recommendations of the forum was released in early 2009.[198] The report highlighted the ongoing development of smart grid related activities occurring both in Ontario and around the world; and provided a list of key recommendations for further development of the Ontario smart grid. The province's plan for all utilities to equip their residential and small business customers with a smart meter by 2010 (Ontario's Smart Metering Initiative) is well underway, and remains an integral part of this development.

Although significant impacts of the economic downturn have been observed in demand levels, no major generation or transmission projects have been significantly deferred or cancelled as a result of the current economic climate.

Other Region-Specific Issues

There are no other issues to report.

[198] http://www.ieso.ca/imoweb/pubs/smart_grid/Smart_Grid_Forum-Report.pdf

REGION DESCRIPTION

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.

QUÉBEC INTERCONNECTION

QUÉBEC REGION – NPCC

EXECUTIVE SUMMARY

The demand forecast growth for the 2010 NERC Long Term Reliability Assessment (LTRA) over the 2010-2019 period is revised downward compared to the 2009 NERC LTRA. The compound average growth is about 0.9 percent over the current assessment period, and this is 0.4 percent lower than in the 2009 LTRA. This downward revision of the demand forecast is explained mainly by a difficult economic period characterized by a general economic slowdown affecting most economic sectors but especially the large industrial sector. The Total Internal Demand in the 10th year (2019/2020) of this assessment is 40,099 MW while the Net Internal Demand is 38,849 MW.

The Existing Capacity resources for the 2010/2011 period total 42,320 MW, of which 38,855 MW is categorized as Existing Certain. Wind power capacity contribution is accounted for in this 2010 LTRA. A portion of wind power installed capacity is under contract with Hydro-Québec Production and is still de-rated by 100 percent as it was in earlier LTRA assessments. All other wind generation sites are under contract with Hydro-Québec Distribution and a capacity credit equivalent to 30 percent of nameplate capacity is retained for this portion. In 2011, the Gentilly-2 nuclear generating station (G.S.) (675 MW) is temporarily out of service for a complete refurbishment. Gentilly-2 will be back in service for Québec's 2012/2013 peak period with a 25 MW additional capacity for a total of 700 MW.[199]

In the last Québec Balancing Area Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on March 10, 2010, it was found that the Required Reserve Margin for reliability criterion compliance, expressed as a percentage of the Total Load Forecast should be 9.3 percent for the short term and around 12 percent in the long run. Over the current assessment period the reserve margin based on existing capacity and net firm transactions varies between 9.2 percent and 0.3 percent. The reserve margin based on deliverable resources varies between 9.4 percent in the first year and 10.6 percent in the last year of this assessment. This indicates that Québec Area meets its target reserve margin in the first year but needs additional resources to be above the region target reserve margin for the remaining period of this assessment. The reserve margin on prospective and potential resources varies between 15.2 percent in the first year and 15.8 percent in the last year of this assessment. This clearly shows that the Québec Area is above the target reserve margin throughout the current assessment period.

Over this assessment's time horizon, a total of 997 miles of new transmission lines are expected to be placed in-service. There is no transmission reliability concern identified for the Québec Balancing Authority area.

INTRODUCTION

The Québec Balancing Authority area is one of NPCC's five Control Areas and Hydro-Québec is the major contributor to Québec's electricity market. Hydro-Québec generates, transmits and distributes most of

[199] Hydro-Québec has announced earlier in August that the refurbishing of Gentilly-2 will be delayed by one year.

the sub-region's electricity. In large part, it uses renewable generating options such as hydro power, and supports the development of 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. Moreover, Hydro-Québec contributes to research on new generation options such as hydrokinetic power, salinity gradient power and geothermal energy. It also conducts research in energy-related fields such as energy efficiency.

A wind capacity contribution is introduced for the first time in this LTRA and has been estimated to the equivalent to 30 percent of nameplate capacity. This result is specific to wind generation sites under contract with Hydro-Québec Distribution and has not been used for other wind farms. Around 3,500 MW of wind nameplate capacity will be in service through 2015.

The last Québec Balancing Area Interim Review of Resource Adequacy, approved by NPCC's Reliability Coordinating Committee, on March 10, 2010, indicates that the Long Term Required Reserve Margin, expressed as a percentage of the Total Load Forecast, should be around 12 percent in order to meet the NPCC reliability criterion of a maximum 0.1 day per year of Loss of Load Expectation (LOLE). This Interim Review is available on NPCC's web site. [200]

DEMAND

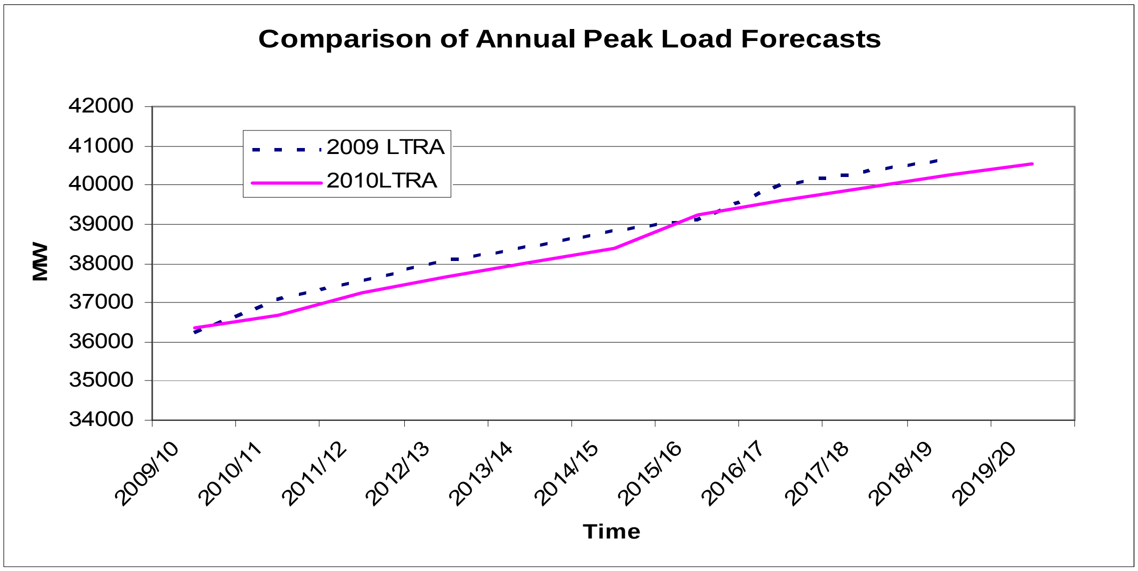
The 2010 LTRA compound annual growth rate is 0.9 percent. Compared to the 2009 LTRA annual growth rate, it is 0.4 percent lower. The load forecast used in this 2010 LTRA is the last revision issued in August 2010. The lower growth rate in the 2010 LTRA is mainly due to the general economic slowdown. This difficult economic situation has affected all sectors of the economy and in particular, large industries. Moreover, the new demand forecast includes a new energy savings target which is higher than the previous. The chart below compares the annual peak load forecasts in the 2010 LTRA and in the 2009 LTRA.

Average weather conditions and uncertainties in demand are modeled by recreating each hour of a 36-year period (1971 through 2006) under the current load forecast conditions. Moreover, each year of historic data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of peak hour in each of those 252 scenarios.

Hydro-Québec Distribution (HQD) is the only Load Serving Entity (LSE) in the Québec sub-region. Thus, the load forecast is conducted for the Québec Balancing Authority Area represented as a single entity and there is no requirement for demand aggregating. Resource evaluations are based on coincident winter peak forecasts, with base case and high case scenarios.

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

Figure NPCC-6



Load Forecast Uncertainty (LFU) includes weather and structural uncertainties. Demand variation modeling related to weather uncertainties was discussed previously. Structural uncertainty is caused by the evolution of economic and demographic parameters affecting demand (Prices, GDP, net family income, number of households, new residential developments, etc).

Global uncertainties are calculated as the independent combination of these two categories. Global uncertainty, expressed as a percentage of load is higher in this review than in the previous one. Higher structural uncertainties can be explained by the greater economic risks associated with the deployment of large industrial projects. No changes have been made to Hydro-Québec's demand forecast method since the last Long Term Reliability Assessment (LTRA).

The Québec Area peak information is coincident. Resource evaluations are based on coincident winter peak forecasts, with base case and high case scenarios.

Hydro-Québec Distribution's goal for 2010 is 4.5 TWh in recurring energy savings. The Energy Efficiency Plan (EEP) set a target of 11 TWh/year for 2015. The EPP focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers.

> Hydro-Québec Distribution's goal for 2010 is 4.5 TWh in recurring energy savings. The Energy Efficiency Plan (EEP) has set a new target of 17 TWh/year for 2021. The EPP focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers.
>
> Hydro-Québec has two Demand Response Programs totalling 1,750 MW specifically design for peak shaving during winter cold periods:
>
> - Interruptible demand programs — mainly addressed to large industrial customers — have an impact of 1,500 MW on peak demand.

- A voltage reduction scheme with 250 MW of demand reduction at peak has been set up by TransÉnergie.

In Québec, there are no Renewable Portfolio Standards (RPS) as in other Control Areas. However, some Demand Side Management targets are planned by the Québec Government and Hydro-Québec Distribution has to file monitoring reports to the "Régie de l'énergie du Québec" (Québec Energy Board) in relation to these targets.

Programs and tools for promoting energy saving are the following:

For residential customers:

1. *Energy Wise* home diagnostic
2. *Recyc-Frigo* (old refrigerator recycling)
3. Electronic thermostats
4. *Energy Star* qualified appliances
5. Lighting
6. Pool-filter timers
7. *Energy Star* windows and patio doors
8. *Rénoclimat* renovating grant
9. Geothermal energy
10. New home Novoclimat grant

For business customers – small and medium power users:

1. Empower program for buildings optimization
2. Empower program for industrial systems
3. Efficient products program
4. Traffic light optimization program
5. Energy Wise diagnostic
6. Visilec

For business customers – large power users:

1. Building initiatives program
2. Industrial analysis and demonstration program
3. Plant retrofit program
4. Industrial initiatives program

The Energy Efficiency Program features can be found on Hydro-Québec's Website [201].

[201] http://www.hydroquebec.com/energywise/index.html

GENERATION

In Québec, all new expected resources are renewable such as wind power, biomass and hydroelectric power.

Among existing capacities, the Gentilly 2 generation facility (currently rated 675 MW) is scheduled out of service for refurbishing, and 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. When Gentilly 2 is returned to service, it will include an additional 25 MW of capacity for a total of 700 MW. The TCE generating facility is planned to be out of service until 2015-2016.

The table below summarizes the Existing (certain, other and inoperable) and Future (planned and other) capacity resources at peak through the end of the assessment period.

Table NPCC-7: Québec Capacity

Capacity	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Existing-Certain	38,855	38,180	38,880	38,880	38,880	38,880	39,427	39,427	39,427	39,427
Existing other	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028
Existing-Inoperable	1,437	2,112	1,437	1,437	1,437	1,437	890	890	890	890
Total Existing	42,320	42,320	42,320	42,345	42,345	42,345	42,345	42,345	42,345	42,345
Future-Planned	55	1,133	1,601	1,838	3,103	3,185	3,455	3,850	3,982	3,982
Future-Other	0	0	0	0	0	0	0	0	0	0
Total Internal Capacity	42,375	43,453	43,946	44,183	45,448	45,530	45,800	46,195	46,327	46,327

Variable resources in the sub-region are mostly wind generating resources. Wind generation sites are owned and operated by Independent Power Producers (IPPs). Nameplate capacity is presently 642 MW of which 195 MW is under contract with Hydro-Québec Production (HQP) and is de-rated by 100 percent for this assessment. The rest (447 MW) is under contract with HQD and is derated by 70 percent for this assessment. Around 3,500 MW of wind projects are expected to be on-line through 2015. Capacity credit evaluation has shown that a 70 percent de-rate factor can be safely used for resource adequacy evaluations. Methods used for this assessment are discussed later in this document.

Moreover, approximately 180 MW of the sub-region's capacity is biomass. For the purpose of this evaluation another 125 MW of biomass was expected to be available for the 2012/2013 peak period.

There are no conceptual capacity resources in the Québec Area for this assessment period. However, several projects are under construction or consideration. These projects when completed will provide a significant increase in capacity over the next few years. The projects are:

Eastmain-1 A / La Sarcelle Project

The project consists in building two generating stations (Eastmain-1 A - 768 MW, 2.3 TWh/year and La Sarcelle - 150 MW, 0.9 TWh/year) in the James Bay area, near the existing Eastmain-1 G.S. The project, scheduled for commissioning in 2011/2012, will provide Hydro-Québec's generating fleet with an additional capacity of 918 MW and an additional output of 3.2 TWh per year.

Romaine Complex Project

Hydro-Québec has obtained the necessary approvals to build a 1,550 MW hydroelectric complex on the Rivière Romaine, on the north shore of the St. Lawrence Gulf. The complex will consist of four hydro generating stations with an annual output of 8.0 TWh. Construction has begun in March 2009 and is scheduled to be completed in 2020. The first power station commissioning is planned for 2014.

SM-3 PA Project

The project consists in adding a 440 MW unit to the existing SM-3 generation station on the Sainte Marguerite River. The project is scheduled to be completed in 2014/2015.

Tabaret Project

The project consists in building a 132 MW generating station with an annual energy output of 0.6 TWh located on the upper portion of the Ottawa River. The project is scheduled to be completed in 2019.

Wind Generation Projects

The table NPCC-8 summarizes all wind generation projects, near 2500 MW, that are expected to be in service over the next few years through HQD's first and second calls for tenders.

Table NPCC-8: Wind Generation Projects

Supplier Name	Project Location	Capacity (MW)	Service Entry Date

Northland Power Inc.	St-Ulric-St-Léandre	22.5	December 1, 2010
Northland Power Inc.	Mont-Louis	100.5	December 1, 2011
3Ci	Des Moulins	156	December 1, 2011
Enerfin	De L'Érable	100	December 1, 2011
Invenergy	Le Plateau	138.6	December 1, 2011
St-Laurent Énergies	Saint Robert Ballarmin	80	December 1, 2011
Kruger	St-Rémi	100	December 1, 2012
St-Laurent Énergies	Lac Alfred	150	December 1, 2012
St-Laurent Énergies	Lac Alfred	150	December 1, 2013
St-Laurent Énergies	Massif du Sud	150	December 1, 2012
Venterre	New Richmond	66	December 1, 2012
Venterre	St-Valentin	50	December 1, 2012
Boralex/SEC	Seigneurie de Beaupré #2	132.6	December 1, 2013
Boralex/SEC	Seigneurie de Beaupré #3	139.3	December 1, 2013
B&B VDK	MRC La Matapédia	100	December 1, 2014
St-Laurent Énergies	Rivière du Moulin	150	December 1, 2014
St-Laurent Énergies	Rivière du Moulin	200	December 1, 2015
St-Laurent Énergies	Clermont	74	December 1, 2015

Other generation from biomass, small hydro and wind are expected to be in service in the next few years. These include the following:

- A call for tenders launched in January 2009 for 125 MW of biomass cogeneration.
- A Power Purchase Program for small hydropower projects of 50 MW or less for a total of 150 MW
- A call for tenders launched in April 2009 for 500 MW of new wind-generated capacity developed by communities.

When performing resource assessments Hydro-Québec considers all facilities that are available at peak period. Capacities are adjusted for scheduled maintenance and restrictions. Detailed information in relation with expected forced outages is used as input data for reliability assessment evaluations in the control area.

CAPACITY TRANSACTIONS ON PEAK

The Québec Area has a secured 200 MW firm purchase contract with New Brunswick until October 2011. This firm contract is backed by dedicated generation and firm transmission rights.

The Québec Area also has two firm export contracts for this assessment period:

- 145 MW with Ontario (Cornwall); and
- 310 MW with New England until the end of 2011, but this contract is expected to be renewed for the upcoming years covering this assessment.

TRANSMISSION

In June 2010, a new double-circuit 315 kV transmission line from Chénier to Outaouais has been commissioned which now permits full use of the new 1,250 MW interconnection's capacity with Ontario's Independent Electricity System Operator (IESO). A fourth 1,650 MVA 735/315 kV transformer at Chénier has been commissioned in July. A third 345 MVAR capacitor bank has also been installed at Chénier.

Another sizable 315 kV project under construction is the new Anne-Hébert 315/25 kV transformer station near Québec City. A new 8.2 mile 315 kV line tapped from an existing circuit is also being built to feed this station.

On the longer term, to accommodate load growth, a number of new transformer stations are now in the planning or conceptual phases, and 120 to 315 kV transmission lines will be built to integrate these stations with rest of the existing system.

Different calls for tenders for wind generation have been issued by Hydro-Québec Distribution in the past years. A total of approximately 3,500 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. These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésia Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

A System Reinforcement Project submitted to and approved by the Québec Energy Board (*Régie de l'énergie du Québec*) is still ongoing. Mainly, this includes two Static VAr Compensators to be installed at Chénier 735-kV substation and series compensation on a number of 735-kV lines. Moreover, the *Régie* has also approved the addition of two -200 MVAr inductive branches on the future SVCs to be installed at Chénier substation. 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 ties using the Châteauguay and Phase II interconnections. The project also includes the addition of an SVC at Bout-de-l'Île substation in 2013 along with the addition of a 735 kV section at Bout-de-l'Île and Bergeronnes series compensation nominal current-carrying capacity upgrade in 2014.

Hydro-Québec Production has now started construction of the Romaine River Complex on the Lower North Shore of the St. Lawrence River. TransÉnergie is now in the planning stage for the integration of this project to the system. Four Generating Stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. The first G.S. to be commissioned, Romaine-2 (645 MW), will be integrated in 2014 at Arnaud 735/315 kV substation. The other Generating Stations will be integrated through 2020. Information on the Project is available at: http://www.hydroquebec.com/romaine/index.html

TransÉnergie is also planning the addition of a 735 kV section at Bout-de-l'Île substation in Montréal for the 2013-2014 peak period. This will permit the redistribution of load around Montréal and a new 735 kV source in Montréal's east area.

Moreover, a new 735 kV switching station named Aux Outardes is presently being considered near the actual Micoua substation. It is needed to alleviate capacity problems at Micoua and to reduce the impact from certain loss-of-two-line events at Micoua after 2015.

No potential reliability impacts are expected from not meeting in-service target dates for wind generation integration projects. Most projects are 100 MW or less, and a delay in any one of them, when taken individually, has practically no effect on the overall system reliability within Québec.

The same is true for in-service delays for future transformer stations. Delays may have local impacts such as delaying load transfers from other substations and may affect local load pockets, but will have no effect on the overall bulk system reliability within Quebec.

Hydro-Québec TransÉnergie does not foresee any transmission constraints during this assessment's horizon that could significantly impact reliability. 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.

We summarize below significant substation equipment (other than load or transformer stations) planned to be commissioned during the next years.

2010-2011

- 345 MVAR 315-kV shunt capacitor at Chénier 735/315 kV substation (Done)
- Fourth 1,650 MVA 735/315 kV transformer at Chénier substation (Done)
- Double-circuit 315 kV line from Chénier to Outaouais (Done)
- Wind Integration (Ongoing)
- 735 kV breaker addition at Duvernay 735/315 kV substation (Ongoing)

2011-2012

- 345 MVAR 315-kV shunt capacitor at Duvernay 735/315 kV substation

- Two -300/300 MVAR SVCs at Chénier 735/315 kV substation (Including -200 MVAR extra reactive branches for each SVC)
- Series compensation at Jacques-Cartier 735-kV (35 percent compensation on two 735-kV lines, #7024 and #7025)
- 315-kV integration of Eastmain-1A and La Sarcelle Hydro
- Wind integration

2012-2013

- Wind integration

2013-2014

- Wind integration
- New 735-kV section at Bout-de-l'Île substation and integration into Line 7009
- New -100/300 MVAR SVC at Bout-de-l'Île 735/315 kV substation in Montréal
- Biomass integration

2014-2015

- Wind integration
- Two 1,650 MVA 735/315 kV transformers at Bout-de-l'Île 735/315 kV substation
- 315 kV integration of Romaine-2 Hydro (Lower North shore of St. Lawrence River)
- 2 X 180 MVAR 315 kV shunt capacitors at Arnaud 735/315 kV substation
- 2 X 180 MVAR 161 kV shunt capacitors at Saguenay 735/161 kV substation
- New 735 kV switching station ("Aux Outardes") near existing Micoua substation

2016 +

- 315 kV integration of Romaine-1, 3 and 4 Hydro (Lower North shore of St. Lawrence River)

Operational Issues

With the exception of Gentilly-2 refurbishment, there are no significant anticipated generation unit outages, variable resources, transmission outages or temporary operating measures that could impact reliability during the next ten years. The scheduled outage of the 675 MW Gentilly-2 nuclear generation station from mid 2011 to mid 2012 will not impact reliability. This was documented in the Québec 2009 Interim Review of Resource Adequacy. The introduction of variable resources (wind), transmission additions and temporary operating measures are not expected to negatively impact reliability in the Québec Area during the next ten years.

There are no environmental or regulatory restrictions related to atmospheric emissions that could negatively impact reliability since non-hydro resources account only for a small portion of total resources. Plants using oil or jet fuel are used only for peaking purposes and are refuelled by boat or truck prior to the winter season. Natural gas is used at a single cogeneration plant and is delivered under a firm natural gas purchase contract.

No reliability concerns resulting from high-levels of demand response resources are anticipated in the Québec Balancing Authority area. Demand response resources consist only of interruptible load programs totalling approximately 1,500 MW which are used only during winter cold periods. Interruptible load programs are planned with participating industrial customers. All customers are regularly contacted before the peak period (Generally during autumn) so that their commitment to provide their capacity when called during peak periods is ascertained. These programs are in operation for a number of years and according to the records, the customer response is highly reliable.

Another 250 MW of voltage reduction is considered as Demand Response with a focus on avoiding specific distribution lines which feed prioritized customers. Extensive testing of the system has prompted Hydro-Québec Distribution to include it in its Demand Response Portfolio. This program is not expected to vary considerably in the near future.

An area of concern for the Québec Balancing Authority stems from winter peaking demands being higher than expected. Operational planning studies are being continuously conducted by TransÉnergie, the Québec Area controller. Yearly peak demand period studies are conducted to assess system conditions during winter peak periods. Extreme weather in Québec translates into very low temperatures and high demand during the Winter Operating Period. Through a transmission planning criterion, transmission planning studies must take into account a 4,000 MW load increase above the normal load forecast on the system during such extreme weather conditions. This is equivalent to 110 percent of system peak load. Québec relies on both internal and external resources to serve this additional load and transmission capacity is planned into the system through the planning criteria.

On an operations horizon, if peak demands are higher than expected a number of measures are available to the System Control personnel. Operating Instruction I-001 lists such measures. These vary from limitations on non guaranteed wheel through and export transactions, operation of hydro generating units at their maximum output (away from optimal efficiency), use of import contracts with neighbouring systems, starting up of thermal peaking units, use of interruptible load programs, and eventually reducing 30-minute reserve and stability reserve, applying voltage reduction, making public appeals, and ultimately using cyclic load shedding to re-establish reserves.

Presently, the only variable resources integrated in the Québec Area are wind generation resources. The actual nameplate capacity of this type of generation is 642 MW but the maximum output to this day has been 555 MW. A wind generation power forecasting system has been in use for more than three years and is subject to periodical improvements. Hourly updated forecasts are available to System Control staff and cover a 48-hour time horizon. Wind generation forecasting is used in the Balancing Area's forecasting software packages.

The Québec Balancing Authority area is a separate Interconnection from the Eastern Interconnection into which other NPCC Areas (sub-regions) are interconnected. The system's installed capacity is in the order of 42,300 MW but as little as 12,000 MW of capacity may be connected to the grid during summer low-load periods. System inertia may therefore be quite low. The Québec Interconnection's frequency does not follow the Eastern Interconnection's frequency. Frequency regulation is therefore a concern for the Area. The normal frequency profile is 59.5 to 60.5 Hz and frequency excursions following a normal (NPCC) contingency may reach 58.5 to 61.5 Hz. Interconnections with other NPCC areas consist either of HVdc ties or radial generation to and from neighbouring systems.

To date, wind generation variability has not significantly impacted day to day operation of the system and the present level of wind generation does not require particular operating procedures.

In the longer term, a number of foreseeable impacts on system management may show up and will be addressed:

- Wind generation variability on system load and interconnection ramping.
- Frequency and voltage regulation problems.
- Increase of start-ups / shutdowns of hydroelectric units due to load following coupled with wind variability. Generally units must be operated within certain limits to ensure efficiency.
- Reduction of low load operation flexibility due to low inertial response of wind generation coupled to must-run hydroelectric generation.

RELIABILITY ASSESSMENT ANALYSIS

The following table shows the Area target reserve margin and projected reserve margins for the 2010 LTRA period based on existing capacity and net firm transactions, anticipated capacity resources, prospective capacity and potential resources. The required reserve margin for the Québec Balancing Authority area is 9.3 percent for the short term and around 12 percent for the long term. The existing reserve margin is below the Region required reserve margin over this assessment period. Since the anticipated reserve margin is also below the target reserve margin, the Québec Area may needs additional resources to meet reliability criterion. Most of these resources are actually in construction.

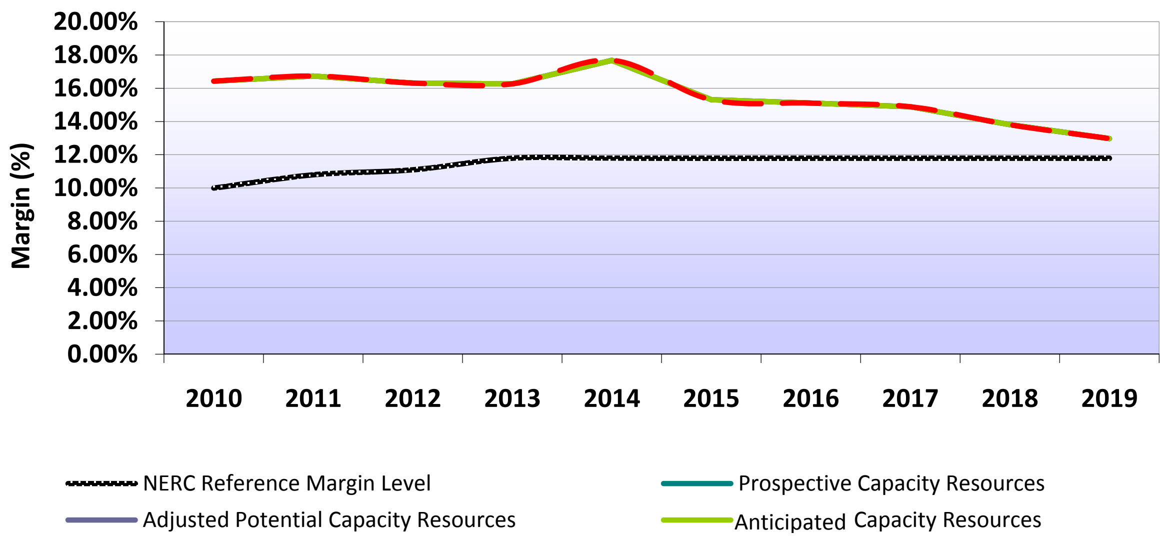
The table below summarizes reserve margins for the subregion.

Table NPCC-9: Projected Québec Balancing Authority Area Reserve Margins for 2010 LTRA

Reserve Margin (%)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
Region target	9.3	10.8	11.1	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Existing-Certain	9.2	6.1	6.4	5.3	3.0	1.2	2.0	1.3	0.5	0.3
Anticipated Capacity	9.4	9.6	10.8	10.4	11.4	9.6	11.0	11.3	10.8	10.6
Prospective Capacity	15.2	15.2	16.4	15.9	16.8	14.9	16.3	16.6	16.0	15.8
Potential Resources	15.2	15.2	16.4	15.9	16.8	14.9	16.3	16.6	16.0	15.8

The chart below shows the projected reserve margins compared to the NERC Reference Margin Level.

Figure NPCC-7: Winter Peak Reserve Margin Projections



To assess its resource adequacy, the Québec Balancing Authority area uses a Loss of Load Expectation (LOLE) criterion of 0.1 day per year. The simulation model is represented by an hourly load system . This criterion complies with the Resource Adequacy Criterion in the NPCC Reliability Reference Directory #1 – "Design and Operation of the Bulk Power System", which is stated as follows:

"Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages rates and deratings, assistance over interconnections with neighbouring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available procedures."

The latest resource adequacy study is described in the 2009 Québec Interim Review of Resource Adequacy. This study shown that the Québec Area meets the NPCC Resource Adequacy Criterion under the base case scenario of peak load forecast for the entire period covered by this Interim Review (2009-2013). For the high case scenario, it was shown that the Area also meets the NPCC Resource Adequacy criterion for the first two years and needs to purchase 500 MW and 750 MW over the base case to comply with reliability criterion for the last two years.

Short term (*i.e.*, 1–4 years) and long term (5 years and more) Reserve Margins requirements are treated slightly differently. The long term required reserve is set equal to the reserve calculated for the fourth year of the assessment. This four-year time frame gives sufficient time for building new peaking units or for finding new demand side resources.

All resources needed to meet the target margin level are summarized in the table below. Except for 200 MW of firm imports from New Brunswick during 2011 and 2012 on-peak periods, no external resources are added to the total resources for the ten next years. The Québec Area has sufficient resources to meet its 9.3 percent target reserve margin for the next peak period while relying only on internal resources.

From 2011 until 2020, the Québec Area needs additional resources to meet its target reserve margin. The procurement Plan 2011-2020 of Hydro-Québec Distribution will address this situation. The Plan will be file to the Régie de l'énergie (Québec energy board) before the November 1st, 2010.

Thus, when performing resource adequacy reviews, up to 1,100 MW of capacity purchases from the New York Balancing Authority Area is considered.

Table NPCC-10: Planned Reserves				
Year	Net Internal Demand (A)	Deliverable Capacity Resources (B)	Planned Reserves (C=B -A)	Planned Reserves % (D=C/A)
2010/2011	35,195	38,505	3,310	9,4
2011/2012	35,743	39,158	3,416	9,6
2012/2013	36,122	40,026	3,904	10,8
2013/2014	36,486	40,263	3,777	10,4
2014/2015	37,288	41,528	4,240	11,4
2015/2016	37,982	41,610	3,628	9,6
2016/2017	38,211	42,427	4,216	11,0
2017/2018	38,467	42,822	4,355	11,3
2018/2019	38,779	42,954	4,175	10,8
2019/2020	38,849	42,954	4,105	10,6

Energy Criterion

Hydro generating plants are classified into three categories: run-of-river plants, annual reservoir and multi-annual reservoir hydro generating plants. Low water inflows are coped with in different ways for each category:

- Run-of-river plants: relatively constant hydraulic restrictions from year to year.
- Annual reservoir hydro units: during a year with normal water inflows, these reservoirs are almost full at the beginning of the winter. If annual water inflow is low, hydraulic restrictions increase.
- Multi-annual reservoir hydro units: the target level for multi-annual reservoirs is approximately 50 to 60 percent full in order to compensate or store inflows during periods of below or above normal water inflows. Hydraulic restrictions increase during a period of low inflows.

After a severe drought having a 2 percent probability of occurrence, hydro generation on the system would suffer additional hydraulic restrictions of about 500 MW above the "normal conditions" restrictions. Stream flows, storage levels and snow cover are constantly being monitored allowing Hydro-Québec to plan margins to cope with drought periods.

Hydro-Québec's energy requirements are met for the greatest part by hydro generating stations, located on different river systems and scattered over a large territory. The major plants are backed by multiannual reservoirs (water reserves lasting more than one year). The Québec Balancing Authority area can rely on those multi-year reservoirs and on some other non-hydraulic sources, including fossil generation, allowing it to cope with inflow variations.

To assess its energy reliability, Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to run through sequences of two or four years of low inflows having a 2 percent probability of occurrence. Hydro-Québec must demonstrate its ability to meet this criterion three times a year to the Québec Energy Board. The last assessment can be found on the Québec Energy Board web site. [202]

To smooth out the effects of low inflow cycles, different means are identified:

- reduction of the energy stock in reservoirs to a minimum of 10 TWh beginning in May
- external non-firm energy sales reductions
- use of thermal generating units during an extended time period
- off-peak purchases from neighbouring areas

Renewable Capacity Integration

There are no transmission-limited resources in the Québec Balancing Authority area. Resources are integrated into the system as firm capacity resources at peak. However, due to constraints with the second Hydro-Québec Distribution call for tenders, some wind resources in the Gaspésie Peninsula may be transmission limited during some low load periods in such situations where high wind generation cannot be sunk in local load pockets. This does not affect the resource adequacy assessments as wind resources are de-rated by 100 percent during Summer Operating Periods and the above situation cannot happen in winter.

The Area has no Renewable Portfolio Standards. However, some targets expressed in new megawatts of renewable resources are set by the Québec Government and specific calls for tenders are launched by Hydro-Québec Distribution in order to meet these targets. If additional resources are required for resource adequacy purposes, HQD is responsible for driving the procurement process which is open to all resources.

For resource adequacy assessments, the wind resource capacity credit is evaluated at 30 percent of nameplate capacity as shown in the 2009 Interim Review of Resource Adequacy. Studies regarding wind power capacity contribution were conducted in 2009. Weather data covering the period between 1971

[202] http://www.regie-energie.qc.ca/audiences/Suivis/Suivi-D-2008-133_Criteres/

and 2006 were used in order 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: Multi-Area Reliability Simulation (MARS), and FEPMC, a Monte-Carlo model developed by Hydro-Québec. The results from both models indicate the appropriateness of using a 30 percent contribution during winter season. Since this result considers only wind farms under contract with HQD, all other wind installed capacity in the control area was completely de-rated. Moreover, during the Summer Operating Period, all wind resources are de-rated by 100 percent.

All operational considerations related to renewable are treated in the appropriate section (section 5).

Demand Response and Retirements

According to the results of specific studies conducted in 2007, the capacity contracted in the scope of interruptible load programs totaling approximately 1,500 MW is de-rated up to 30%, depending of the program, for reliability assessment purposes.

According to the extensive testing conducted and considering the persistence of voltage reduction , the 250 MW is an evaluation of net impact of the program.

SPSs

A total of 2,500 MW of UVLS is installed in Québec. It has been designed to operate following extreme contingencies involving the loss of two or more 735-kV lines tripped out in the load area of 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. No additional load is expected to be assigned to UVLS during the next 10 years.

It is not planned that special protection systems or remedial action schemes will be installed in lieu of planned bulk power transmission facilities in the Québec Balancing Authority area.

Process for Catastrophic Events

Hydro-Québec maintains a permanent 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 Order #24 “Service Continuity and Emergency measures” and Corporate Policy “Our Security” form the basis on which the Plan is built. The Corporate Plan is prepared by the Industrial Security Group at Hydro-Québec. It includes the plan’s objectives, risks covered by the plan, the organization around the plan (Steering Committee and Coordinating Committee), communications, and updating. Risks cover a large array of situations, for example, rupturing of a dam or dike, a nuclear incident, extensive damage to transmission lines and stations, forest fires, unavailability of computer systems or telecommunications systems, biological risks, cyber criminality, terrorism, etc. The Plan also provides links with the Québec Civil Security Organization and other civil, military, or medical organizations. This Corporate Plan directs Hydro-Québec’s divisions to elaborate and maintain their own sectorial plan according to their field of activities.

Hydro-Québec's Intranet Website (Internal to the Organization) has a number of web pages pertaining to the Plan where employees can find information on the Plan and its deployment as well as courses and training possibilities.

Hydro-Québec TransÉnergie's own planning process for catastrophic events is not necessarily based on a number of particular events such as earthquakes, hurricanes, major fuel disruptions, geomagnetic induced currents, forest fires or loss of a major import path, although specific orders, operating procedures and operating instructions are in force for many of these situations. The Plan is based on eight different types of risk which the system has a probability of experiencing. These risk types are associated with criteria determining their impact on the system. Studies have determined the probability of occurrence and an impact level on a scale from 1 to 9 is associated with the risk type.

For example, one risk type is "Major System Event" with a "Loss of Load" impact criterion, based on service continuity. An Impact Level from 1 to 3 represents a less than 500 MW loss of load whereas an Impact Level of 9 represents a 10,000 MW or more loss of load. Different Impact Level scales and probabilities exist for different types of risk.

For each risk type, a file has been developed defining the risk, possible source events, potential impacts, risk evaluation (Probability of occurrence), mitigation procedures, post-mortem and follow-up requirements.

The Planning Process involves four high level concepts, namely Prevention, Readiness, Post-event intervention and Restoration. These include, among others, communications procedures, personnel training, on-site exercises and follow-ups. The Planning Process requires leadership from Management so that all management structures and all proper procedures are in place at all times. A specific team assures that all documentation is updated and posted. This stems from Corporate Order #24 previously mentioned.

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 which must be assessed under specified conditions. For NPCC, this includes an Extreme Contingency Assessment with, for example, 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, or the sudden loss of fuel delivery systems to multiple plants. A similar standard (TPL-004) exists for NERC. Not all of these events apply to TransÉnergie. For example, only one natural gas fired plant exists on the Québec system, representing only 547 MW, so that a pipeline failure is of little consequence in this case. However, since bulk transmission is 735 kV, TransÉnergie physically limits the number of 735 kV lines in a common right-of-way to a maximum of two lines, because the loss of a right-of-way has a definite impact. Sudden dropping of large load centers, loss of generation stations, loss of a 735 kV switching station are extreme events covered by Special protection Systems (SPSs) which limit the event's impact on the system.

In the case of an extreme contingency leading to a system blackout, there is an automatic device called SPSR (French acronym for "System Separation Solution") that acts locally at a number of 735 kV stations to close-in sacrificial Zinc Oxide surge arrestors before the system dismantles. System collapse is accompanied by over voltages which would damage equipment if not dampened by the surge arrestors. This makes it possible to restore the system in minimum time with maximum equipment availability after a blackout. The surge arrestors themselves must be replaced after such an event.

Planning Studies

TransÉnergie, as Transmission Planner, performs formal system planning studies, impact studies for generation, load and interconnection integration and NPCC Comprehensive Review Assessments. All these studies and assessments are conducted as per NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" and according to NERC TPL standards.

For example, a planning study titled "Transmission System reinforcement for Year 2011" is a large scale study of the 735-kV system to cover all impacting changes on the system through 2012, a number of operating limitations due to reactive power supply and the integration of the new 1,250 MW interconnection with Ontario. An excerpt from the report shows that transmission system base case stability was verified according to the usual criteria. The system cannot at the same time transmit all the upcoming additional generation and still conform to TransÉnergie's design criteria. The constraining events are the simultaneous loss of two 735 kV lines south of La Vérendrye and Jacques-Cartier, the simultaneous loss of both poles of the Multi Terminal DC Network in synchronous operating mode and the loss of a line south of La Vérendrye after the outage of another line south of this substation and a 1,500 MW flow reduction in the corresponding corridor.

For the aforementioned events, system instability characterized by fast or slow voltage drops on the system is observed. This behavior is due to a shortage of reactive power on the system. To assure system stability for these events a number of solutions have been put forward, which include additional reactive power sources.

The proposed solution includes the following elements:

- Addition of two series compensation banks at Jacques-Cartier 735-kV substation to compensate the lines to Chamouchouane by 35 percent.
- Addition of a (-100 to 300 MVAR) Static VAr Compensator (SVC) at Chénier 735-kV substation.
- Addition of a new shunt reactor remote tripping device.
- Addition of a new 345 MVAR shunt capacitor bank.

Other studies such as 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.

Moreover, transient and voltage stability studies are performed continuously by TransÉnergie to establish system operating transfer limits on all possible system configurations.

TransÉnergie has a criterion for minimum dynamic reactive requirements. Due to system geography and configuration (generation centers are remote from load centers and system is made up of long 735-kV lines) this is not applied to generators but to synchronous condensers and Static VAr Compensators distributed along the system. There are 20 SVCs and synchronous condensers on the system, each with a nominal reactive power range of -100 to +300 MVAR. The steady state operating range is -50 to +50 MVAR per compensator, so that a 250 MVAR margin per compensator is available as dynamic reactive reserve. (Up to 5,000 MVAR total). Moreover, a significant amount of 735-kV 330 MVAR reactors may be switched on and off the system to continually keep the compensators within their operating range. The SVC and synchronous condenser operating range is strictly monitored during operations.

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

Table NPCC-11: Voltage Limits on the Transmission System

Nominal Voltage	Normal Limits				Emergency Limits			
	Low Limits		High Limit		Low Limit		High Limit	
	kV	p.u.	kV	p.u.	kV	p.u.	kV	p.u.
735 kV	725	0.985	760	1.034	698	0.95	765	1.04
315 kV	299	0.95	331	1.05	284	0.90	347	1.10
230 kV	219	0.95	242	1.05	207	0.90	253	1.10
Interconnections	--	0.95	--	1.05	--	0.90	--	1.05

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

New Technologies

Hydro-Québec intends to deploy a number of new technologies, systems and tools to improve bulk power system reliability in the future. The following challenges are identified in the future:

- Integrating renewable energy generation of various types, outputs and locations.
- Increasing exchanges between networks.
- Improving interconnected system reliability.
- 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.

TransÉnergie's system consists of an extensive 735 kV network underlain with 315 kV, 230 kV and 120 kV subsystems totaling close to 23,000 circuit miles. The system uses telecommunications and advanced protection and control applications to ensure its reliability and improve its performance. This will continue into the future. The system is planned according to NPCC and NERC Planning Standards but with additional criteria that consider system topology and substation characteristics. Special Protection Systems (SPSs) to ensure reliability (for extreme events) are presently in use and will continue to be used.

Recently, a new Planning Criterion has been added to the TransÉnergie Planning Standards to address the problem of system voltage sensitivity to load variations and interconnection ramping. The criterion quantifies acceptable voltage variations on the 735-kV system. Like other Planning Standards, meeting this standard may require additional equipment or proper mitigating measures. Moreover, meeting Planning Standards may require the use of SPSs and/or automatic actions as mentioned above. These include Remote Generation Rejection and Load Shedding, Under Voltage Remote Load Shedding, Under Frequency Load Shedding, and Automatic Shunt Reactor Switching.

Other technologies such as synchronous condensers, Static VAr Systems, 735-kV series compensation, multi-band power system stabilizers (MBPSS), HVdc systems and a variable frequency transformer (VFT) are in use. Such systems are planned for future system upgrades or for generation integration as needed.

For more than two decades now, TransÉnergie has been operating an angular displacement measuring system to accurately monitor and register system frequency and angular displacement between major 735-kV generating stations and load centers. This is used for on-line reporting and provides priceless post-mortem data for all system events involving frequency variations and angular displacements. The system also measures voltage and current distortion and is used for monitoring harmonic content during solar magnetic disturbances.

Conversion to digital relaying is now being implemented and along with other digital electronic devices this will improve fault detection and clearing but also produce precise data that will set new maintenance standards. Maintenance will be "just-in-time", triggered by collected data analysis.

Simulation tools are constantly being developed by TransÉnergie for operations planning. This, among others, involves weather forecasting associated with load forecasting involving local variations in order to achieve substantial gains in terms of precision. Moreover, the TransÉnergie Operation Planning Department, with the help of Hydro-Québec's Research Institute (IREQ) and Université de Liège in Belgium, is developing a number of system simulation software packages for in-house use. These include on-line dynamic security assessments (DSA), voltage sensitivity due to load/generation variations, massive stability simulations, voltage stability, real-time load modeling and research on motor load modeling. DSA applications have been the object of joint (TransÉnergie and IREQ) IEEE papers.

Another project aims at regulation systems and SPS improvement in order to upgrade transfer capability and improve system reliability. This includes installation of MBPSSs in a great number of Generating Stations, new regulation circuits for the dynamic shunt compensation equipment, new relaying for SPSs, new control strategies for HVdc converters, development of severity indices for angular and voltage stability, etc. The Project is also studying the possibility of introducing a type of global regulation for dynamic shunt equipment (as opposed to regulation based on local parameters) implying Measurement Units, a Data Concentrator, Control Units, all linked by synchronized digital communications.

Technological innovation plays an important role in the evolution of TransÉnergie's transmission system. For example, an inspection and maintenance robot (LineScout) is being developed presently. This is a remote-operated robot used for live-line inspection and maintenance tasks. It has various sensors and features the ability to cross over obstacles on the line.

Presently, TransÉnergie is performing a technological review of different HVdc systems for the Châteauguay HVdc Interconnection converters refurbishment. Châteauguay is a 1,000 MW interconnection commissioned in 1984 and the HVdc converter system must eventually be replaced. Three manufacturers have been approached and three technologies are available namely, Classic Thyristor Line Commutated Converter technology, Capacitive Commutated Converter technology and Voltage Source Converter technology with IGBTs (Insulated Gate Bipolar Transistors). The possibility of upgrading to 1,250 MW is also being verified.

No Smart Grid programs have been fully implemented at Hydro-Québec during the past year. However, Hydro-Québec is pursuing a project called IMAGINE that uses automated maintenance and remote monitoring data management to improve system management efficiency. Through digital technologies such as remote monitoring, telemetry and remote uploading and diagnostics, maintenance operations can be targeted more precisely and some of these can be remotely performed. In 2009, 32 substations were connected to a remote maintenance center near Montréal and a second remote maintenance center was opened in Québec City.

In the short term, there are no project slow-downs or cancellations which may impact reliability. However, in the long term, it is possible that some small renewable projects could deferred or simply canceled. If needed, new call for tenders could be launched.

OTHER REGION-SPECIFIC ISSUES

The Québec Area, when performing different reliability assessments according to NPCC and NERC requirements, takes into account any development that may affect its reliability and presents all necessary measures to avoid negative impacts.

SUBREGION DESCRIPTION

The Québec Area is winter peaking. Summer peak load is typically about 55 percent of winter peak load. The all-time internal peak demand was 37,230 MW set on January 16, 2009. Summer peak demands are in the order of 21,000 MW. Installed capacity in 2010 is around 42,300 MW of which 39,700 MW (94 percent) is hydroelectric capacity (Renewable energy). Existing wind capacity totals 642 MW and is expected to grow to 3,500 MW through year 2015. Transmission voltages on the system are 735, 315, 230, 161 and 120 kV. Transmission line length presently totals about 33,244 km (20,658 miles).

The Québec Balancing Authority area is a separate Interconnection from the Eastern Interconnection into which other NPCC Areas are interconnected. TransÉnergie — the Transmission Owner and Operator in Québec — has interconnections with Ontario, New York, New England and the Maritimes. Interconnections consist of either HVdc ties or radial generation or load to and from the neighboring systems. The population served is around seven million and the Québec Area covers about 1,668,000 km (644,300 square miles). Most of the population lives in the St. Lawrence River basin, and the largest load area is in the southwest part of the province, mainly around the Greater Montréal area, extending down to the Québec City area.

TEXAS INTERCONNECTION

TRE

EXECUTIVE SUMMARY

The unrestricted coincident long-term demand forecast for the TRE Region ranges from 64,052 MW in 2010 to 74,709 MW in 2019 and is lower in comparison to last year's forecast for each year of the forecast period due to the expected slower recovery from the economic recession. The 10th year peak Total Internal Demand is 74,467 MW and the 10th year peak Net Internal Demand is 72,791 MW. The TRE Region has 74,817 MW of Existing-Certain generation and approximately 8,895 MW Existing-Other generation, representing an increase of 2,965 MW of Existing-Certain since the 2009 LTRA. Future capacity that is expected to be available for the bulk of the assessment period includes 2,020 MW of gas fired generation, 1,944 MW from coal, 145 MW of biomass, and 1,326 MW nameplate capacity from wind turbines. TRE has an adequate reserve margin through 2014 but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2015.

Approximately 110 miles of new or rebuilt 345kV transmission lines have been completed since the 2009 Long-Term System Assessment. A large number of transmission projects consisting of over 5,300 miles of new 345 kV lines will be coming into service within the next five years, primarily due to the inclusion of the new lines that have been ordered by the Public Utility Commission of Texas (PUCT) to complete its Competitive Renewable Energy Zones (CREZ) transmission plan. There are no known transmission constraints that appear to significantly impact reliability across the TRE Region.

Table TRE-1: TRE Regional Profile

	2010	2019
Total Internal Demand	63,810	74,467
Total Capacity	86,260	87,941
Capacity Additions	90	1,770
Demand Response	1,398	492

Wind generation is expected to result in congestion on multiple constraints until the new CREZ transmission lines are added between west Texas and the rest of the ERCOT system; these lines are currently scheduled to be completed by the end of 2013. From an operational perspective, the increasing reliance on wind generation in off-peak periods is expected to increase operating challenges. ERCOT ISO continues to develop protocols, tools and procedures to meet these challenges. For example, ERCOT ISO has developed a wind ramp forecasting tool to aid in the operation decisions used to prepare for periods of potential high wind variability and has modified the non-spin reserve procurement method specifically to address potential wind-ramp events identified in the day-ahead forecast.

The TRE Region has significant studies in progress looking at the reliability impacts of integrating variable resources. A voltage ride-through study, initiated in 2009 and due to be complete in 2010, is evaluating the capability of wind generation resources to stay on-line during voltage disturbances. The Region has also initiated an analysis to optimize the reactive capability necessary to support the CREZ facilities and the associated wind generation.

INTRODUCTION

The TRE 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 10-year compounded annual growth rate for the system for 2010-2019 is 1.72 percent. TRE has an adequate reserve margin through 2014 but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2015.

The TRE Region continues to make improvements regarding wind integration, including two new operational initiatives that include a modification to the non-spinning reserve method and a wind ramp-forecasting tool. A large number of new 345 kV transmission projects will be coming into service within the next five years, primarily to reduce congestion between west Texas wind generation and the rest of the ERCOT system. The TRE Region also has planning studies in progress to looking at the reliability impacts of integrating variable resources.

DEMAND

The 2010 long-term demand forecast for the TRE Region from 2010-2019 is lower in comparison to last year's forecast for 2009-2018 in each year of the forecast period. The reduction in the forecasted system peak demands is due to the slower-than-expected recovery of the economic recession, which is reflected in the economic assumptions upon which the forecast is based. The 10-year compounded annual growth rate for the system peak, from 2009-2018, in last year's forecast was 2.04 percent and the 10-year system peak growth rate for 2010-2019 in this year's forecast is 1.72 percent. The lower 10-year growth rate in this year's forecast is a result of more conservative assumptions due to the slow economic recovery.

The peak demand forecast for this summer peaking Region is based on the economic indicators that have been found to drive electricity usage in the TRE Region's eight weather zones. The economic factors which drive the 2010 ERCOT Long-Term Hourly Demand Forecast[203] include per capita income, population, gross domestic product (GDP), and various employment measures that include non-farm employment and total employment. The economic indicators and variables included in the ERCOT weather zone models are designed to reflect the impacts of the major drivers for peak demand and energy consumption.

The forecasted peak demands are produced by ERCOT ISO for the TRE Region, which is a single Balancing Authority area, based on the Region-wide actual demands. The actual demands used for forecasting purposes are coincident hourly values across the TRE Region. The data used in the forecast is differentiated by weather zones. The weather assumptions on which the forecasts are based represent an average weather profile (50/50). An average weather profile is calculated for each of the eight weather zones in TRE, which are used in developing the forecast. To assess the impact of weather

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

variability on the peak demand for TRE, alternative weather scenarios are used to develop extreme weather load forecasts. One scenario is the one-in-ten-year occurrence of a weather event. This scenario is calculated using the 90th percentile of the temperatures in the database spanning the last fifteen years. These extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The extreme temperature assumptions consistently produce demand forecasts that are approximately 5.0 percent higher than the forecasts based on the average weather profile (50/50). Together, the forecasts from these temperature scenarios are usually referred to as 90/10 scenario forecasts.

A 2007 Texas state law[204] mandated that at least 20 percent of an investor-owned utility's (IOU's) annual growth in electricity demand for residential and commercial customers shall, by December 31, 2009, be met through Energy Efficiency programs each year. The IOUs are required to administer energy savings incentive programs, which are implemented by retail electric and Energy Efficiency service providers. Some of these programs, offered by the utilities, are designed to produce system peak demand reductions and energy consumption savings and include the following: Commercial and Industrial, Residential and Small Commercial, Hard-to-Reach, Load Management, Energy Efficiency Improvement Programs, Low Income Weatherization, Energy Star (New Homes), Air Conditioning, Air Conditioning Distributor, Air Conditioning Installer Training, Retro-Commissioning, Multifamily Water & Space Heating, Texas SCORE/City Smart, Trees for Efficiency, and Third Party Contracts.

In general, utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities[205]. According to the latest assessment, utility programs implemented in 1999-2008 produced 1,125 MW of peak demand reduction and 3,014 GWh of annual electricity savings in the year 2008. Most of this demand reduction is accounted for within the load forecast and only the expected incremental portion for each year is included as a demand adjustment.

Loads acting as a Resource (LaaRs) providing Responsive Reserve Service provide an average of approximately 1,062 MW of dispatchable, contractually committed Demand Response during summer peak hours based on the most recently available data. LaaRs are considered an offset to peak demand and contribute to the reserve margin.

ERCOT's Emergency Interruptible Load Service (EILS) is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "firm" load, and represent contractually committed interruptible load. Based on past EILS commitments, approximately 336 MW of EILS load can be counted upon during the 2010 summer peak, increasing by 10 percent per year, for an expected 792 MW in 2019.

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

[205] http://www.texasefficiency.com/report.html

Generation

The TRE Region has 74,817 MW of Existing-Certain generation, approximately 8,895 MW Existing-Other generation, and 2,449 MW Existing-Inoperable. In addition, the Region has 4,224 MW of Future, Planned capacity slated to go into service by 2014. Conceptual capacity ranges from 2,489 MW in 2011 to 5,317 MW in 2014.

TRE has existing wind generation nameplate capacity totaling 9,117 MW and that capacity is expected to increase to 10,443 MW by 2014; however, only 8.7 percent of the wind generation nameplate capacity is included in the Existing-Certain value used for margin calculations, based on a study of the effective load-carrying capability of wind generation in the Region. Consequently, the expected on-peak capacity of wind generation resources ranges from the current value of 793 MW to 908MW by 2014. The remaining existing wind capacity amount is included in the Existing-Other generation amount. Of the Existing-Certain amount, 91 MW is biomass, and 145 MW of additional biomass is included in the Future, Planned capacity.

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 from the appropriate state and federal agencies specifying the conditions for operation. Future capacity that is expected to be available for the bulk of the assessment period includes 2,020 MW of gas fired generation, 1,944 MW from coal, 145 MW of biomass, and 1,326 MW nameplate capacity from wind turbines. Of the 1,326 MW of nameplate wind capacity, only 115 MW, or 8.7 percent, contribute to margin calculations. Conceptual capacity is comprised of projects that have progressed beyond feasibility studies and have secured a more substantial investment by the developer. Of the 53,989 MW in this Conceptual category, 4,762 MW can be attributed to wind capacity that counts toward the reserve margin, 29,544 MW is the de-rated portion of the installed nameplate capacity of the wind, 549 MW to solar, 50 MW to biomass, with the remaining 19,084 MW to conventional fuel sources. Historically, only twenty-two percent of projects in this category come to fruition. There is inadequate project history available to reasonably predict, by fuel type, the capacity that may eventually become operational.

Capacity Transactions

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

For the assessment period, TRE 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.

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

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 Public Utility Commission of Texas (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.

Several new 345kV lines are under construction. The Salado to Hutto portion of the Clear Springs/Zorn-Hutto-Salado project is expected to be in service before the summer peak in 2010. The Clear Springs/Zorn to Hutto portion is expected to be in service before the summer peak in 2011. A new line from San Miguel to Lobo (near Laredo) is expected to be in-service in 2010. There are also several additional new 345kV transmission lines expected to be in service by peak 2011. Several projects in the Dallas/Fort Worth, Corpus Christi, and San Antonio areas are planned to support reliability in these Regions. There are no known transmission constraints that would significantly affect reliability which are not addressed by these projects. 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.

Other significant substation equipment installed or planned for the TRE Region includes:

- Parkdale SVC, DFW Region
- Belair Thyristor Switched Capacitor, Houston Region
- Crosby Thyristor Switched Capacitor, Houston Region
- Holly Statcom, Central Texas

OPERATIONAL ISSUES

There are no known major facility outages, environmental restrictions or regulatory restrictions that could significantly impact reliable operations expected over the ten-year assessment period. The outage coordination process is designed and undertaken to address any reliability issues, as well as potential constraints, associated with planned outages due to transmission construction or maintenance. 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 of approximately 3 percent of peak, in addition to Regulation Service 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 plan (EEA), as described in Section 5.6.6.1 of the ERCOT Protocols[206] and Section 4.5 of the ERCOT Operating Guides[207]. The EEA plan includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the DC ties, and ISO-instructed demand reduction.

ERCOT has recently implemented two new operational initiatives that include a modification to the Non-Spinning Reserve method in order to assist in managing wind variability during off peak periods and a wind ramp-forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods. The Wind Ramp alert system is now in service and aids in operational decisions to prepare for periods that the wind may vary. The tool looks ahead 15 minutes, 60 minutes and 180 minutes and predicts the probability of ramp events. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.

There are no anticipated reliability concerns resulting from high-levels of Demand Response resources. ERCOT limits the Demand Response participation of LaaRs at 50 percent of the hourly Responsive Reserve Service procurement, for which the minimum requirement is 2,300 MW. LaaRs are deployed automatically via UFR trip in response to frequency excursions below 59.7 Hz or through verbal dispatch during system emergencies such as Energy Emergency Alerts. There are no anticipated reliability concerns with distributed resource integration at this time.

Reliability Assessment Analysis

TRE has an adequate reserve margin from 2010 (20.5 percent) to 2014 (12.6 percent) but the reserve margin falls below the 12.5 percent minimum level used throughout the assessment period starting in 2015 (11.9 percent), based on new generation with signed interconnection agreements, expected mothballed resources, and existing resources (see Figure TRE-1). The minimum reserve margin target of 12.5 percent is applied to each year of the ten year assessment period and is based on a Loss-of-Load Expectation (LOLE) analysis[208], resulting in no more than one day in ten years loss of load.

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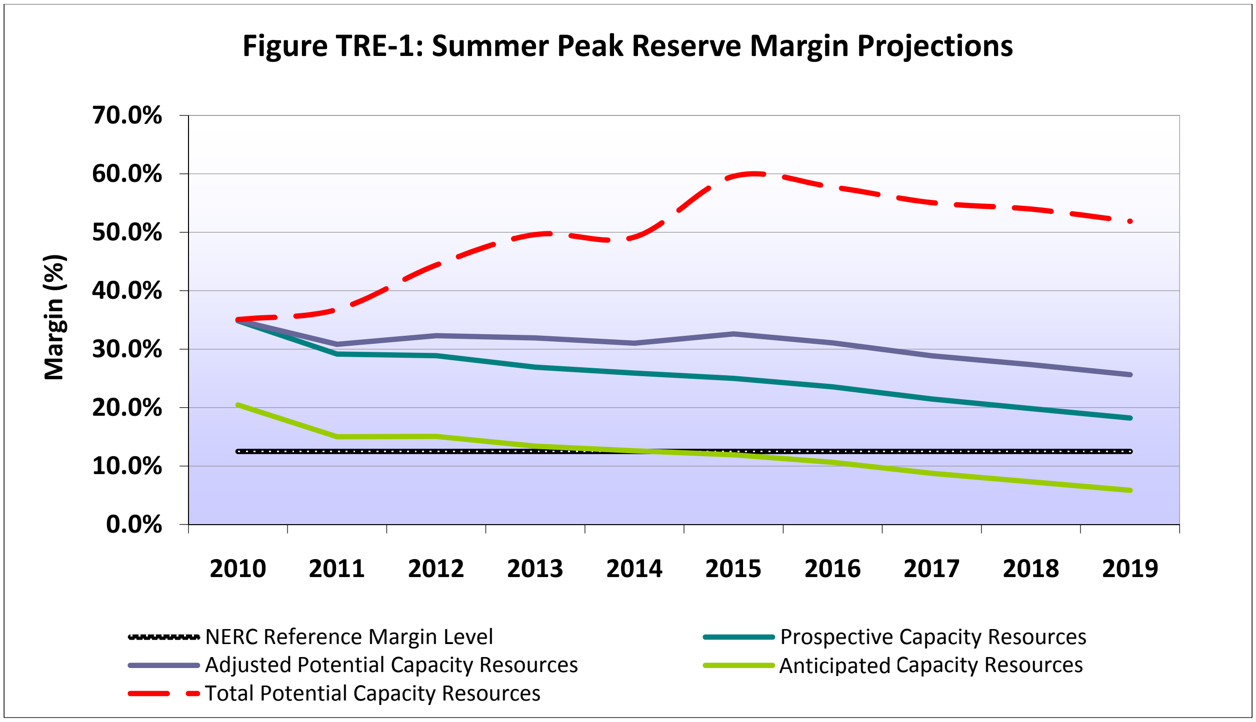
[206] http://www.ercot.com/mktrules/protocols/current.html

[207] http://www.ercot.com/mktrules/guides/operating/current

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



TRE relies almost entirely on internal resources to serve its load and reserves. TRE currently has 86,170 MW of installed capacity, with additional signed interconnection agreements for 5,435 MW of new generation capacity over the next ten years. In addition, 2,544 MW of existing resources are expected to be mothballed prior to 2011.

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

Reserve margins for the Region have decreased since last year's assessment due to the increase in expected mothballed resources (2,544 MW) and decrease in planned generation (1,792 MW) . This reduction in generation has offset the expected positive impact of lower forecasted demand and additional planned resources on the reserve margin.

With multiple sources of fuel supply, traditional fossil fuel interruptions are not expected to be an issue in TRE. 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.

The Renewable Portfolio Standard for Texas (including areas of Texas that are outside the TRE 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 times the renewable capacity goal. The 2025 target has already been met.

Only 8.7 percent of existing wind generation nameplate capacity is counted on for Certain generation, based on an analysis of the effective load carrying capability of wind generation in the Region.[209] The remaining existing wind capacity amount is included in the 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.

The continued installation of new wind generation in west Texas is expected to result in congestion on multiple constraints within and out of west Texas for the next several years until new bulk transmission lines are added between west Texas and the rest of the ERCOT system. This is not expected to limit generation deliverability during peak periods, since only 8.7 percent of the installed wind capacity is counted for reserve purposes. The PUCT has ordered the construction of approximately $5 billion in transmission system upgrades as a part of the Competitive Renewable Energy Zone (CREZ) process[210]. This transmission is intended to enable wind generation in west Texas to be able to serve load in the rest of the TRE Region and is expected to be completed by the end of 2013.

Unlike many other ISOs and control areas, ERCOT ISO does not administer Demand Response products or services that are specifically designed for peak load reduction. ERCOT ISO's approach to Demand Response can be described as enabling load participation in Ancillary Services markets (particularly Responsive Reserves) and supplementing those Ancillary Services with short-term capacity based Demand Response that is subject to deploy during grid emergencies. In both cases, Demand Response resources are procured through market mechanisms and provide the service round the clock. ERCOT ensures that its Demand Response resources will perform as expected by monitoring online Ancillary Services capacity from load resources in real-time, conducting after-the-fact availability analyses, and conducting annual load-shed testing of Demand Response resources to ensure they are equipped with the necessary communications and curtailment equipment. No changes are anticipated to this approach at this time.

In the TRE Region, when a generation unit seeks to retire or mothball its facility, ERCOT protocols mandate a reliability study to ensure that the retirement or mothballing does not affect system reliability. If reliability is affected, transmission projects or mitigation plans are developed to mitigate the impact. Until such plans or projects can be completed, the unit may be contracted as a reliability must-run (RMR) unit to remain available for service. ERCOT currently has RMR agreements with two generators that were scheduled to retire but were determined to be needed to maintain transmission system reliability until an RMR Exit Strategy that relieves this need can be implemented.

The TRE Region currently has under-voltage load shed (UVLS) schemes established in the following areas: Houston (~5,100 MW), Dallas/ Fort Worth (~2,400 MW), Laredo (~160 MW) and the Rio Grande Valley (~340 MW). UVLS deployments are intended to provide a "safety net" in case other operating actions are not enough to resolve under voltage problems. UVLS are not generally relied upon to

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

[210] Competitive Renewable Energy Zones Transmission Optimization Study, http://www.ercot.com/news/presentations/2008/index, p. 24ff

survive NERC Category B and C events, and system reinforcements may be made to limit the amount of load shed that is necessary under certain NERC Category D events. The Rio Grande Valley UVLS scheme is intended to prevent local voltage collapse that may result following certain Category C contingencies. ERCOT plans grid enhancements as needed in a continuous process and does not plan for additional UVLS schemes as a reliability tool.

There is no established planning process for catastrophic events. To the extent that ERCOT ISO is made aware of an impending crisis, the ERCOT ISO will take preventative measures as necessary, including ordering withdrawals of planned outages, ordering additional generation on-line, inquiring about extra assistance across the DC Ties, as well as performing special engineering studies to evaluate potential worst-case scenarios.

The TRE Region has significant studies in progress looking at the reliability impacts of integrating variable resources. A voltage ride-through study, initiated in 2009 and due to be complete in 2010, is evaluating the capability of wind generation resources to stay on-line during voltage disturbances. The Region has also initiated an analysis to optimize the reactive capability necessary to support the CREZ facilities with associated wind generation.

The Planning Authority and Transmission Planners (TP) in the Region participate in the planning process, including an annual ERCOT Five-Year Transmission Plan and the ERCOT Long Term System Assessment. In addition, each TP performs additional analysis of their portion of the ERCOT system as necessary. The ERCOT Five-Year Transmission Plan is performed to identify transmission system needs for years one through five and satisfies, in part, NERC TPL-001, TPL-002 and TPL-003 requirements. The 2009 Five-Year Transmission Plan analysis identified 41 reliability projects to be implemented between 2010 and 2014.

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 ISO staff then propose 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 are Corpus Christi, Houston, Dallas/Fort Worth, Rio Grande Valley, South to Houston generation, South to Houston load, North to Houston generation and North to Houston load. Operating Procedure Manual for the Transmission and Security Desk[211], 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 category B contingencies and a 2.5 percent margin for category C contingencies[212]. 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

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[211] http://www.ercot.com/mktrules/guides/procedures

[212] Section 5 of the ERCOT Operating Guides, http://www.ercot.com/mktrules/guides/operating/

TOs to develop corresponding transmission projects to resolve the lack of voltage stability margin and to TOPs for their re-assessment for the operating horizon.

No new special protection systems (SPS) or remedial action schemes were identified during the 2009 Five-Year Transmission Plan analysis.

Active power and reactive power flow-control devices, such as phase-shifting transformers, switchable series reactors and FACTS devices have been added to the ERCOT system to mitigate transmission constraints and improve system efficiency. In addition, ERCOT ISO staff and TRE stakeholders are evaluating and studying 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 TRE 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 usage. 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 TRE Region. While such Demand Response will not be dispatched by the ERCOT ISO, it is expected to have a currently positive impact on Regional load factors and peak load management.

Region Description

The TRE 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 TRE Region is a summer-peaking Region with a population of about 22 million covering approximately 200,000 square miles. The TRE Region has 274 Registered Entities and encompasses about 85 percent of the electric load in Texas with an all-time peak demand of 63,400 MW set in July, 2009. TRE performs the Regional Entity functions described in the Energy Policy Act of 2005 for the TRE Region in which ERCOT operates.

WESTERN INTERCONNECTION

WECC

INTRODUCTION

The Western Electricity Coordinating Council (WECC) is comprised of eight subregions: WECC-Canada (CANW), Northwest (NORW), Basin (BASN), Rockies (ROCK), Desert Southwest (DSW), California-North (CALN), California-South (CALS), and WECC-Mexico (MEXW). The geographic boundaries of these subregions are depicted on the map in the Regional Description section of this assessment.

WECC loads are growing at a lower rate than reported in 2009 — the projected 2010 summer Total Internal Demand of 148,365 MW is projected to increase by 1.4 percent per year to 168,237 MW in 2019.

Reserve margins in all of WECC's subregions have improved due to decreased load growth and increased generation capacities. The planning reserve margins used for this report were developed using a building block method. The planning reserve margins will be referred to as target margins in this assessment. These target margins range between 11.4 and 20.0 percent, with an overall average of 14.3 percent in summer and 13.9 percent in winter.

Inter-subregional transfers were 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 Power Supply Assessment (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.

In Table WECC-1: Region and subregion Reserve Margins (below), the Anticipated Capacity Resources (ACR) line includes the projected transfers and the peak values of the Existing-Certain and Future-Planned resources. The Adjusted Potential Resources (APR) line includes the ACR values and the adjusted potential resources.

Table WECC-1: Region and subregion Reserve Margins									
	WECC	*CANW	*NORW	BASN	ROCK	DSW	CALN	CALS	MEXW
Target Margin	14.3 %	13.2%	20.0%	12.0%	12.3%	13.6%	14.6%	14.8%	14.8%
2010									
ACR Margin	27.9%	15.2%	23.2%	25.2%	37.2%	23.7%	23.5%	31.0%	19.3%
APR Margin	53.5%	34.3%	69.7%	38.3%	51.8%	29.4%	77.9%	52.3%	19.6%
2019									
ACR Margin	38.2%	4.8%	41.7%	15.9%	20.6%	42.9%	39.5%	62.8%	28.9%
APR Margin	76.1%	34.8%	102.8%	36.2%	37.3%	59.2%	92.7%	115.2%	54.2%
* *Reflects the winter Reserve Margins for winter-peaking subregions.*									

When considering only the anticipated capacity resources, the WECC-Canada subregion (CANW) goes below the WECC-developed target margin for that subregion as early as the winter of 2010/2011. When considering the adjusted potential of both the Future-Other (FO) and Conceptual resources, the CANW reserve margin remains above the target margin.

By the summer of 2019, the difference between WECC's anticipated capacity resources (223,388 MW) and WECC's Net Internal Demand (161,684 MW) would be 61,704 MW (38.2 percent reserve margin). This would be 38,583 MW above the target margin. The reserve margin figure does not include serving 6,553 MW of controllable Demand-Side Management (DSM) load. If the controllable DSM load were to be served, the margin would be 32.8 percent. Since the reported capacity resource additions would result in margins that far exceed target margins, it is reasonable to assume that only a portion the reported resource additions will ultimately enter commercial service within the ten-year planning horizon.

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

This self-assessment is based on loads and resources data submitted to WECC in February 2010.

PEAK DEMAND

Total summer internal demand increased by 0.7 percent from 2008 to 2009. Summer temperatures in 2008 were normal to somewhat above normal while summer temperatures in 2009 were generally normal to somewhat below normal. The projected aggregate of 2010 and 2019 summer Total Internal Demand forecasts and the growth rates can be seen in the Table WECC-2, below. The summer Total

Internal Demand is projected to increase by 1.4 percent per year for the 2010 to 2019 timeframe, which is lower than the 1.8 percent projected last year for the 2009 to 2018 period.

Table WECC-2: Summer Coincident Peak Demands (MW)				
	WECC	WECC US	Canada	Mexico
2008 Actual	145,582	127,697	16,955	2,045
2009 Forecast	159,196	139,257	18,071	2,115
2009 Actual	146,650	128,245	16,506	2,077
2008 to 2009 Growth	0.7%	0.4%	-2.6%	1.6%
Deviation from forecast	-7.9%	-7.9%	-8.7%	-1.8%
2010 Projected	148,365	129,072	17,683	2,140
2009 to 2010 Growth	1.2%	0.6%	7.1%	3.0%
2019 Projected	168,237	145,237	22,194	3,125
2010 to 2019 Growth	1.4%	1.3%	2.6%	4.3%

Table WECC-3: Annual Energy Use (GWh)				
	WECC	WECC US	Canada	Mexico
2008 Actual	887,217	744,613	131,541	11,063
2009 Forecast	885,663	738,416	136,560	10,687
2009 Actual	858,793	718,694	129,356	10,743
2008 to 2009 Growth	-3.2%	-3.5%	-1.7%	-2.9%
Deviation from forecast	-3.0%	-2.7%	-5.3%	0.5%
2010 Projected	863,355	719,081	132,919	11,355
2009 to 2010 Growth	0.5%	0.1%	2.8%	5.7%
2019 Projected	1,006,267	821,597	167,953	16,717
2010 to 2019 Growth	1.7%	1.5%	2.6%	4.4%

WECC specifically directs its BAs to submit forecasts with a one-year-in-two (50/50) probability of occurrence. Most entities based their forecasts on population growth, economic conditions, and normalized weather. WECC has not established a quantitative analysis process for assessing the variability in projected demands due to the economy, but most of the forecast submissions took into consideration the current economic recession. WECC staff does not perform independent load forecasts. The peak demand forecasts presented here are based on forecasted demands submitted by WECC's 37 BAs.

Energy efficiency programs vary by location and are generally offered and administered by the LSE. Programs include ENERGY STAR builder incentive programs, business lighting rebate programs, retail compact fluorescent light bulb programs, home efficiency assistance programs, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc. For purposes of verification, some LSEs retain independent third parties to evaluate their programs.

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

The total WECC internal demand forecast includes summer Demand Response that increase from 4,148 MW in 2010 to 6,553 MW in 2019. The direct control Demand-Side Management capability is located mostly in California (2,591 MW in 2010 and 4,493 MW in 2019), but DSM programs in other subregions are also increasing with the most prevalent Demand Response programs being air conditioner cycling programs. Interruptible load programs focus on the demand of large water pumping operations and large industrial operations such as mining.

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

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

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

Generation

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

Table WECC-4, below, reflects the WECC summer on-peak capacity for Existing-Certain (EC), Future-Planned (FP), Future-Other (FO), and Conceptual generation resources for the assessment period.

Table WECC-4: Existing and Adjusted Potential Resources (through July 31, 2019)					
	Existing-Certain* (MW)	Future-Planned (MW)	Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**221,443**	**55,633**	**0**	**7,705**	**63,338**
Conventional	152,089	21,822	0	5,202	27,024
Hydro	56,709	3,358	0	885	4,243
Wind	10,041	17,786	0	1,610	19,396
Biomass	2,065	305	0	8	313
Solar	539	12,362	0	0	12,362

** The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak*

Table WECC-5: Projected and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected Resources	**184,468**		**38,920**	**0**	**6,285**	**45,205**
Conventional Projected	134,709		21,822	0	5,202	27,024
Hydro Projected	46,100		1,442	0	579	2,021
Wind Projected	2,180		3,583	0	496	4,079
Biomass Projected	1,030		98	0	8	106
Solar Projected	449		11,975	0	0	11,975
Derates or Maintenance		**36,975**	**16,713**	**0**	**1,420**	**18,133**
Hydro Derate		10,609	1,916	0	306	2,222
Wind Derate		7,861	14,203	0	1,114	15,317
Biomass Derate		1,035	207	0	0	207
Solar Derate		90	387	0	0	387
Scheduled Outages		17,380	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

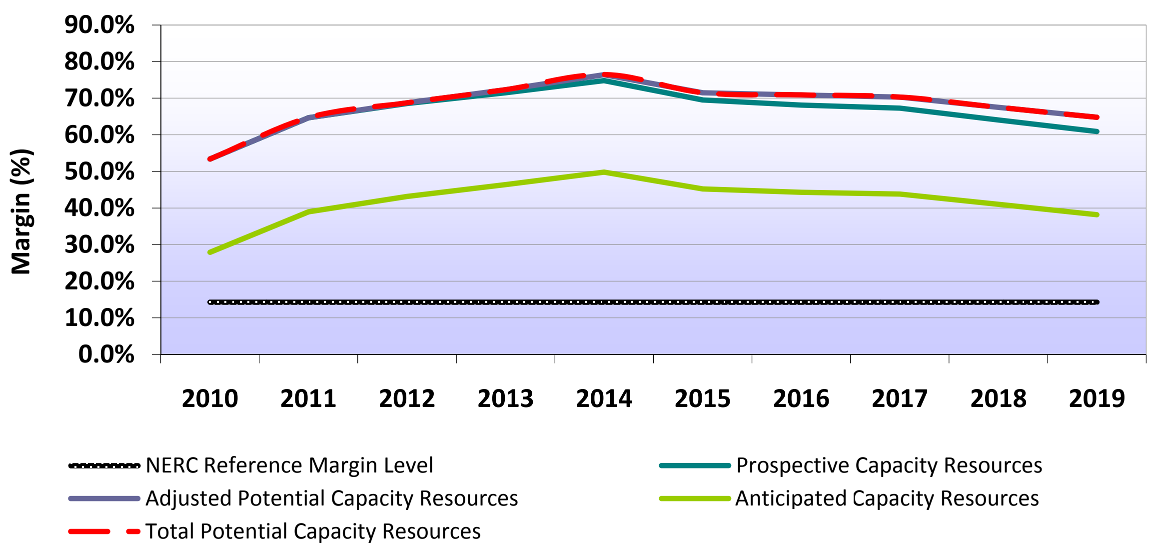
***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

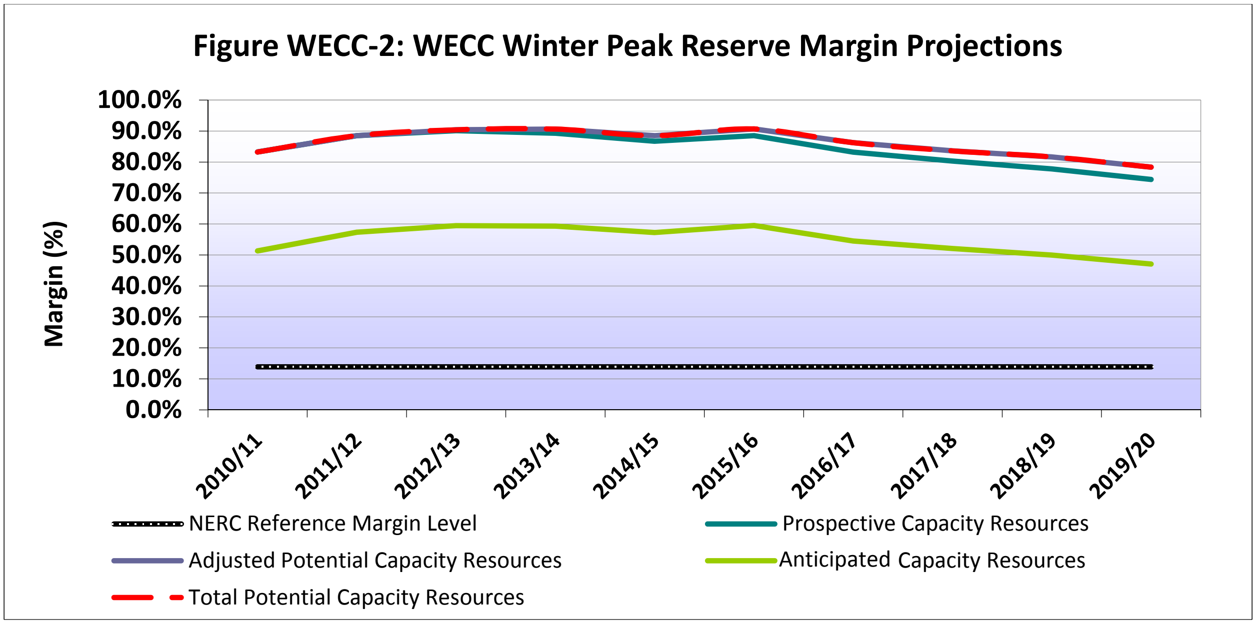
The projected summer peak resources value for July 2010 of 184,468 MW reflects the monthly shaping of variable generation, seasonal ratings of conventional resources, and 17,380 MW of scheduled maintenance planned during this month. The resources not counted toward on-peak capacity total 36,975 MW. The net FP capacity resources projected to be in-service by the end of this assessment period are 38,920 MW. The above two tables provides a breakdown of some of the resource types and their associated capacities.

The WECC LRS has requested the BAs provide a pair of confidence factors. One is applied to the FO 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 7,705 MW and 6,285 MW, respectively. The adjusted on-peak potential is 6,285 MW net after applying an aggregate confidence factor of 100 percent. 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 following figures present the WECC summer and winter margins for various resource addition assumptions. Similar figures in the subregion sections of this assessment present their respective seasonal margins as determined by WECC's resource allocation model.

Figure WECC-1: WECC Summer Peak Reserve Margin Projections





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

1. The analysis for the Northwest subregion may not fully capture the limitations on the ability of the Northwest hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses — both to meet the Northwest load and for export to other subregions — may be unrealistically high.
2. 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.
3. Calculating an area's reserve margin using the Net Internal Demand (total demand minus DSM programs) when DSM programs are not sharable may result in an overstatement of the projected margin.

Table WECC-6: Planning Reserve Target Margins

Target Margin	WECC	WECC-US	CANW	NORW	BASN	ROCK	DSW	CALN	CALS	MEXW
Summer Margin	14.3%	14.7%	11.5%	18.6%	12.0%	12.3%	13.6%	14.6%	14.8%	14.8%
Winter Margin	13.9%	14.1%	13.2%	20.0%	11.5%	13.5%	13.0%	10.5%	11.4%	11.4%

The planning reserve margins or target margins in the above table were derived using the 2010 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

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 14.3 percent. These Reserve Margins were developed specifically for use in the *Long-Term Reliability Assessment* and PSA, and may be lower or higher than some of the state, provincial, or LSE requirements within WECC. These target margins are not requirements for the WECC BAs to meet, but are only for reporting purposes.

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 (RFPs) or rely on the market price signals to spur development of the resources.

Individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in Section III of the WECC Planning Coordinating Committee's Handbook.[213] 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 in this *Long-Term Reliability Assessment* or the PSA analysis. WECC has established a Variable Generation Subcommittee (parallel to NERC's Integration of Variable Generation Task Force) to examine issues related to planning for and operating with large amounts of variable generation on the system.

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[213] WECC's Planning Coordinating Committee's Handbook

PURCHASES AND SALES ON PEAK

For the 2010-2019 period, WECC's analysis modeled no net firm on-peak imports from Eastern Interconnection entities. However, imports may be scheduled across three back-to-back dc ties with Southwest Power Pool, Inc. (SPP) and four of the five back-to-back dc ties with the Midwest Reliability Organization. One WECC entity reports a diversity exchange credit with its counterpart in SPP.

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[214] 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 (see the diagram below) 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.

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.

[214] distribution of generation from facilities that have multiple owners or transfers tied to a specific generation facility.

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 (OTC) limits and invokes schedule curtailments to address the near-term inter and intra-subregion transmission limitations.

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

FUEL

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

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.

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 widespread supply interruptions.

Transmission

For the 2010 to 2019 period, 16,630 circuit miles of 100 through 500 kV transmission line additions have been reported to WECC. The results of the reported data are compiled in Table WECC-7, below.

Table WECC-7: Existing and Future Transmission (Circuit Miles)

	AC Voltage (kV)				
Category	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	49,564	43,356	10,098	16,412	**119,430**
Under Construction as of 1/1/2010	197	729	145	185	1,251
Planned - Completed within first five years	602	1,513	594	2,431	5,140
Conceptual - Completed within first five years	97	604	0	1,247	1,948
Planned - Completed within second five years	252	518	190	2,932	3,892
Conceptual - Completed within second five years	138	165	-42	4,133	4,394
Total Under Construction and Planned Additions	1,051	2,760	929	5,548	10,288
Total Conceptual	235	769	-42	5,380	6,342
Total Under Construction, Planned, and Conceptual Line Additions	**1,286**	**3,529**	**887**	**10,928**	**16,630**
Total Circuit Miles*	**50,527**	**47,003**	**10,557**	**27,489**	**135,576**

**May include projects that are duplicative in nature*

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 may occur during the ten-year assessment period. A delay for most of these projects would not adversely impact system reliability, but the subregion sections of this assessment may identify some projects that could impact local area reliability.

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

Examples include:

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

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in WECC's *Overview of Policies and Procedures for Project Coordination Review, Project Rating Review, and Progress Reports*.[215] 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 (PMU) in the Western Interconnection. The PMUs 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.

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 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.

WECC operations personnel 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.

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

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

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

In addition, most of WECC's entities are members of various reserve sharing groups that may be called on to provide additional energy under prescribed emergency conditions. Some of the reserve sharing

[215] WECC's Overview of Policies and Procedures for Project Coordination Review, Project Rating Review and Progress Reports

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

The integration of increasing levels of variable generation resources, specifically wind and solar, that may be required to meet state or local Renewable Portfolio Standards (RPS) raises operating issues. Integrating these resources reliably into the various areas may require BAs to change how they operate their systems due to the intermittency of the generation from these resources. Variable resources place an increased demand on the traditional resources used to balance their systems. This may cause the BAs to purchase better wind forecasting programs, require an increase in spinning reserves, or develop 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.

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

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

In most cases, the projected retirement of existing generation has been associated with the construction of new resources, thus minimizing any adverse impact from retirements.

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

Reliability Assessment Analysis

WECC does not have an interconnection-wide formal planning Reserve Margin standard. As mentioned, part of the WECC annual Power Supply Assessment[216] (PSA) summer and winter reserve target margins are developed using a building block method. The building block method takes into account factors for weather, forced outages, operating reserves, and operating contingencies. These planning reserve target margins were held constant for the entire study period. One of the goals of the assessment is to identify subregions within the Western Interconnection that have the potential for electricity supply deficits below target margins based on reported total demand, resource, and transmission data. While the Western Interconnection has multiple back-to-back direct current transmission interconnections with the Eastern Interconnection, the margin analysis only considers resources within the Western Interconnection.

There are Reserve Sharing Groups (RSGs) that cover each of the WECC subregions except California and Mexico. In general, the LSEs in each RSG only count on the resources within their RSG. California's Sacramento Municipal Utility District and Turlock Irrigation District BAs are members of the Northwest Power Pool (NWPP) and share reserves across transmission interconnections with other NWPP members. However, for purposes of the 2010 *Long-Term Reliability Assessment*, they are included in the California-North subregion, where they are geographically located.

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

There are several changes in the projections and components of the *2010 Long-Term Reliability Assessment* as compared to the *2009 Long-Term Reliability Assessment*. The effect of the recession has reduced the load growth in the near term, resulting in higher reserve margins and a post recession growth rate that is higher than the near term. The summer peak demand growth rate for the 2010 to 2019 period is 0.1 percent less than the 2009 to 2018 summer peak demand growth rate reported in the *2009 Long-Term Reliability Assessment*.

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

Several states with load internal to WECC have issued state-mandated RPS.[217] These are discussed in the individual subregion sections. The RPS requirements have accelerated the use of renewable resources, a majority of which is wind generation. In some areas, where large concentrations of wind resources have

[216] WECC's Power Supply Assessment

[217] States with Renewable Portfolio Standards

been added, BAs have increased the amount of available regulating reserves to accommodate the increased variability. If this trend continues, BAs with increasing levels of wind generation will likely need to carry additional operating reserves. Additional tools have been implemented to manage wind variability and uncertainty. To help minimize the uncertainty in wind generation output, wind forecasting systems have been implemented by some BAs. In addition, to reduce the amount of additional operating reserves needed, some BAs have developed wind curtailment and limitation procedures for use when generation exceeds available regulating resources.

There are a variety of methods used to account for the capacity of wind resources. Some BAs do not count wind resources toward their on-peak capacity. Others use historical information to project how much capacity they can count toward meeting their demand. Alternately, one BA establishes the capacity value for wind using a Load Duration Curve method, which averages the wind contribution during the highest 90 summer load hours. For this assessment, WECC used wind production curves created by WECC using the National Renewable Energy Laboratory (NREL) synthetic wind data set, at one-hour intervals over three years, 2004-2006. This data covers the U.S. portion of WECC at two kilometer by two kilometer square grid level. It was generated based on detailed weather modeling, initialized from historical conditions. It is not, strictly speaking, historical data. The NREL wind data was aggregated to create wind profiles based on the amount of wind being studied in each state in a particular resource scenario. This resulted in a limited number of profiles being created for each state.

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 the adverse effects of each transmission system's capability to serve its customers, to accommodate planned inter-area power transfers, and to meet its transmission obligation to others. The standards do not require construction of transmission to address intra-Regional transfer capability constraints. WECC's Operating Transfer Capability Policy Committee has a System Operating Limits (SOL) study and review process. This process divides WECC into Regional study groups that are responsible for performing and approving seasonal studies on significant paths to determine the maximum SOL rating.

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

The Annual Study Program[218] 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 subregions. In addition to providing WECC Members with an assessment of the WECC transmission system, the Annual Study Program report helps support compliance with the following requirements in the NERC Reliability Standards relating to Reliability Assessment, Special Protection Schemes, and System Data.

[218] WECC's Annual Study Program

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

If the study results do not meet the expected performance levels established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include:

- an islanding scheme for loss of the AC Pacific Intertie that separates the Western Interconnection into two islands and drops load in the generation-deficit southern island
- a coordinated off-nominal frequency load shedding and restoration plan
- measures to maintain voltage stability
- a comprehensive generator testing program
- enhancements to the processes for conducting system studies
- a reliability management system

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

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

Transmission operators and planners perform reliability studies on their own systems to ensure performance meets or exceeds NERC and WECC standards. As mentioned earlier in the transmission section, the SRWG has an annual study program, 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 the results of these studies are compiled in the study program report.[219]

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

[219] WECC's Technical Studies

The WECC TPL-(001-004)-WECC-1-CR-System Performance Criteria[220] 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 their respective areas are compliant with the WECC criteria and TPL Standards 001 - 004.

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

Each year WECC sends out a data request letter to the Technical Studies Subcommittee and the SRWG asking for areas of "potential voltage stability problems and the measures that are being taken to address the problems throughout the WECC Region." The results of this survey are compiled and posted on the WECC Web site as the Voltage Stability Summary.[221] There are several BAs within WECC that participate in Undervoltage Load Shedding (UVLS) programs. Further details regarding these programs are presented in the subregional sections or are presented in the Voltage Stability Summary.

WECC does not have guidelines for on-site spare generator step-up transformers or spare auto-transformers. Some of the BAs within WECC participate in transformer-sharing programs such as the Edison Electric Institute transformer program. BAs generally maintain an inventory of transformers for their area or system

Regional Description

WECC's 302 members, including 37 Balancing Authorities, represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 71 million people, it is the largest and most diverse of the eight NERC Regional reliability organizations. Additional information regarding WECC can be found on its Web site.[222]

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[220] WECC's TPL – (001 thru 004) – WECC – 1 – CR — System Performance Criteria

[221] WECC's Voltage Stability Summaries

[222] http://www.wecc.biz

WECC-Canada Subregion

Peak Demand and Energy

WECC-Canada is a winter-peaking subregion comprised of the provinces of Alberta and British Columbia. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 2.6 percent and 2.2 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 2.6 percent.

Table WECC-8: WECC-Canada			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	16,955	20,472	131,541
2009 Forecast, Coincident	18,071	21,548	136,560
2009 Actual, Coincident	16,506	20,874	129,356
Growth, Coincident %	-2.6%	2.0%	-1.7%
Deviation from Forecast	-8.7%	-3.1%	-5.3%
2010 Projected, Coincident	17,683	21,243	132,919
Growth, Coincident %	7.1%	1.8%	2.8%
2019 Projected, Coincident	22,194	25,863	167,953
2010 – 2019 Growth %	2.6%	2.2%	2.6%

Summer and winter peak demands for the WECC-Canada subregion increased by -2.6 percent and 2.0 percent respectively, while annual energy use increased by -1.7 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -8.7 percent, -3.1 percent, and -5.3 percent, respectively.

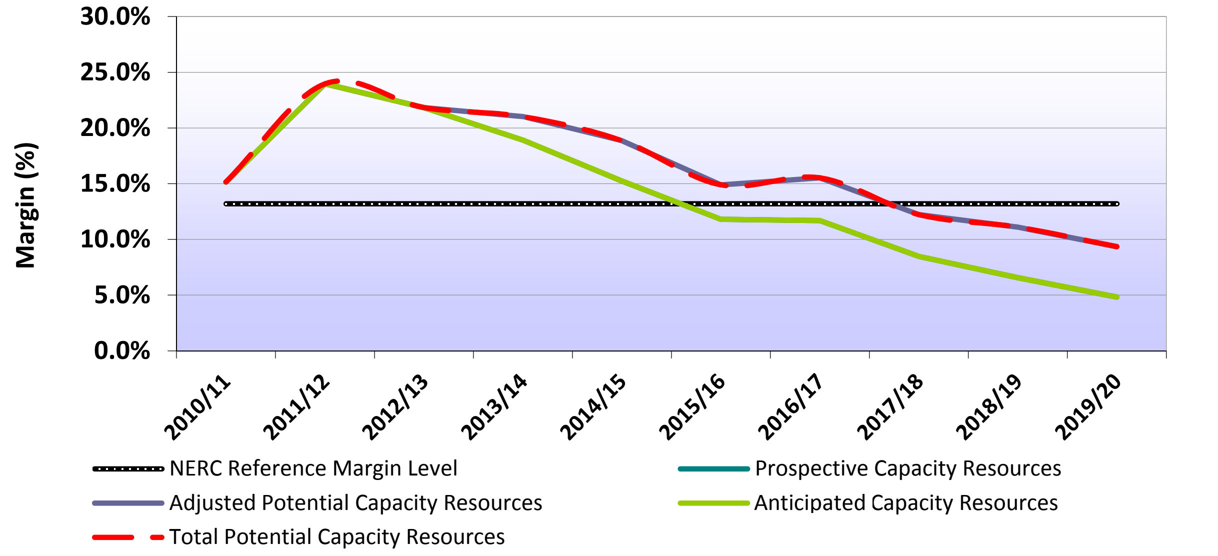
Operational Issues

The WECC-Canada subregion has experienced significant growth in wind resources and expecting that growth to continue. That growth, combined with other significant increases in projected new generation that is remote from load centers, results in the need for significant transmission system upgrades and expansion. While under normal weather conditions the Canadian BAs do not anticipate dependence on imports from external areas during winter peak demand periods, under extreme weather conditions, Canadian BAs may be able to increase diversity exchange imports.

Resource Adequacy Assessment

The WECC-Canada subregion target reserve margins are 11.5 percent for the summer and 13.2 percent for the winter. In Alberta, an projected winter reserve margin that is near the target margin as early as the winter of 2010-2011 highlights the need for resource additions in the subregion. The Canadian entities are aware of the need for resource adequacy and transmission reinforcement and believe that through the open market and proper planning, adequate resources will be available throughout the ten-year assessment period.

Figure WECC-3: WECC CAN Winter Peak Reserve Margin Projections



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

The AESO has instituted a Two-Year Probability of Supply Adequacy Shortfall Metric[223] which is a probabilistic assessment of encountering a supply shortfall over the next two years. The calculation estimates on a probabilistic basis how much load may go without supply over the next two-year period. Based on extensive consultation with their stakeholders, when this unserved energy exceeds 1,600 MWh in any two-year period (equivalent to a one-hour 800 MW shortfall in each of the two years), the party may take certain actions to bridge the temporary supply adequacy gap without affecting investor confidence in the market. The method of bridging the gap may be in the form of 1) Load Shed Service, 2) self-supply and back-up generation support from existing backup generation owned by commercial businesses or other entities, and 3) emergency portable generation.

[223] AESO's Two-Year Probability of Supply Adequacy Shortfall Metric

Table WECC-9: WECC-Canada Existing and Potential Resources (through July 31, 2019)					
	Existing-Certain* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**32,015**	**5,043**	**0**	**1,835**	**6,878**
Conventional	18,358	938	0	-109	829
Hydro	12,653	2,818	0	1,526	4,344
Wind	591	1,092	0	418	1,510
Biomass	413	195	0	0	195
Solar	0	0	0	0	0

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-10: WECC-Canada Projected and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected	**22,372**		**2,520**	**0**	**914**	**3,434**
Conventional Projected	11,115		938	0	-109	829
Hydro Projected	10,849		961	0	885	1,846
Wind Projected	33		466	0	138	604
Biomass Projected	375		155	0	0	155
Solar Projected	0		0	0	0	0
Derates or Maintenance		**9,643**	**2,523**	**0**	**921**	**3,444**
Hydro Derate		1,804	1,857	0	641	2,498
Wind Derate		558	626	0	280	906
Biomass Derate		38	40	0	0	40
Solar Derate		0	0	0	0	0
Scheduled Outages		**7,243**	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

Fuel Supply and Delivery

Wind generation is increasing rapidly in the area. Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the WECC-Canada subregion has 591 MW, which is derated to 33 MW during the summer peak period. Since the wind resources exhibit fluctuations in output, BAs with relatively large amounts of wind generation are investigating the costs and options for integrating wind. Careful and site-specific assessments are needed to minimize adverse consequences that may occur.

Transmission Assessment

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-11: WECC-Canada Transmission Line Circuit Miles

Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	10,229	7,087	148	3,658	21,122
Under Construction as of 1/1/2010	0	148	0	14	162
Planned - Completed within first five years	0	455	0	203	658
Conceptual - Completed within first five years	0	0	0	0	0
Planned - Completed within second five years	0	19	0	304	323
Conceptual - Completed within second five years	0	0	0	0	0
Total Under Construction and Planned Additions	0	622	0	521	1,143
Total Circuit Miles*	**10,229**	**7,709**	**148**	**4,179**	**22,265**

**May include projects that are duplicative in nature*

Because of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of accommodating internal power movement from generation sites to load centers.

Power flow studies have been conducted by the transmission planning authorities and in 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.

Preliminary analysis for WECC's 2010 Power Supply Assessment results indicates that transmission constraints occur between the United States and Canadian portions of the NWPP due to economic diversity exchanges.

Approvals of need for a number of system reinforcements have been received from the Alberta provincial regulator. One of these is for the development of approximately 105 kilometers (65 miles) of 240 kV transmission line to accommodate several new wind generation developments in southwest Alberta. This development has a projected in-service date of June 2010. Other projects include the installation of two 600-MVA 240 kV phase shifting transformers (the first in Alberta) to be used to balance the flows between the northwest and the northeast Regions of the province. AESO's transmission plan[224] can be found at http://www.aeso.ca.

Planning efforts continue on a number of other major system reinforcements including supply into the Fort Saskatchewan and Fort McMurray areas of Northeast Alberta. This reinforcement will likely be a combination of 500 kV and 240 kV developments. Planning efforts are also continuing on reinforcing the main north–south transmission grid in Alberta. For various reasons the need approval for this project was rescinded by the regulator. It is anticipated this project will be in-service in the 2012 time frame.

AESO has an Under Voltage Load-Shedding (UVLS) scheme. There are approximately 300 MW currently connected to the UVLS. This does not influence AESO's reliability assessment.

A Calgary-area transmission must run (TMR) procedure addresses 240 kV transmission grid-loading issues and ensures voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta, near Calgary, and assist in maintaining overall system security.

British Columbia relies on hydroelectric generation for 90 percent of its energy production. British Columbia Transmission Corporation (BCTC) is responsible for the planning, operation, and maintenance of British Columbia's publicly owned transmission system. The BCTC is addressing constraints between remote hydro plants and the Lower Mainland (LM) and Vancouver Island (VI) load centers.

The Vancouver Island Transmission Reinforcement[225] project was completed in December 2008 and involved the removal of two 138 kV lines (one submarine) and replacing them with a 230 kV double-circuit infrastructure, including a 230 kV underwater cable between Arnott substation and Vancouver Island terminal. A key transmission shortage that faces BCTC currently is the Interior to LM path. The Interior to Lower Mainland (ILM) Transmission Project[226] is the BCTC's 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.

[224] AESO Long-term Transmission System Plan

[225] BCTC's Vancouver Island Transmission Reinforcement

[226] BCTC's Interior to Lower Mainland Transmission Project

The BCTC is planning to rely on the existing 905 MW conventional steam plant located in the major load center and the 1250 MW Canadian entitlement from the NWPP U.S. to meet the Lower Mainland/Vancouver Island resource requirements in the interim period. The ILM reinforcement project will increase the total transfer capability of the interior to lower mainland area grid and the new 230 kV cable increased the transfer capability from the lower mainland area to Vancouver Island.

BCTC has Under Voltage Load-Shedding (UVLS) schemes installed for Lower Mainland and Vancouver Island systems to prevent voltage collapse. These schemes monitor the voltage at the key substations in Vancouver Island and 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. The BCTC is not expecting to install additional UVLS.

NORTHWEST (NORW) SUBREGION

PEAK DEMAND AND ENERGY

The Northwest is a winter-peaking subregion comprised of all or major portions of the states of Montana, Oregon, and Washington. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 1.1 percent and 1.1 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 1.2 percent.

Table WECC-12: Northwest

	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	25,048	32,123	174,212
2009 Forecast, Coincident	25,481	29,943	167,544
2009 Actual, Coincident	25,444	32,508	163,143
Growth, Coincident %	1.6%	1.2%	-6.4%
Deviation from Forecast	-0.1%	8.6%	-2.6%
2010 Projected, Coincident	23,855	28,649	157,810
Growth, Coincident %	-6.2%	-11.9%	-3.3%
2019 Projected, Coincident	26,359	31,514	175,639
2010 – 2019 Growth %	1.1%	1.1%	1.2%

Summer and winter peak demands for the Northwest subregion increased by 1.6 percent and 1.2 percent respectively, from 2008 to 2009 while annual energy use increased by -6.4 percent.

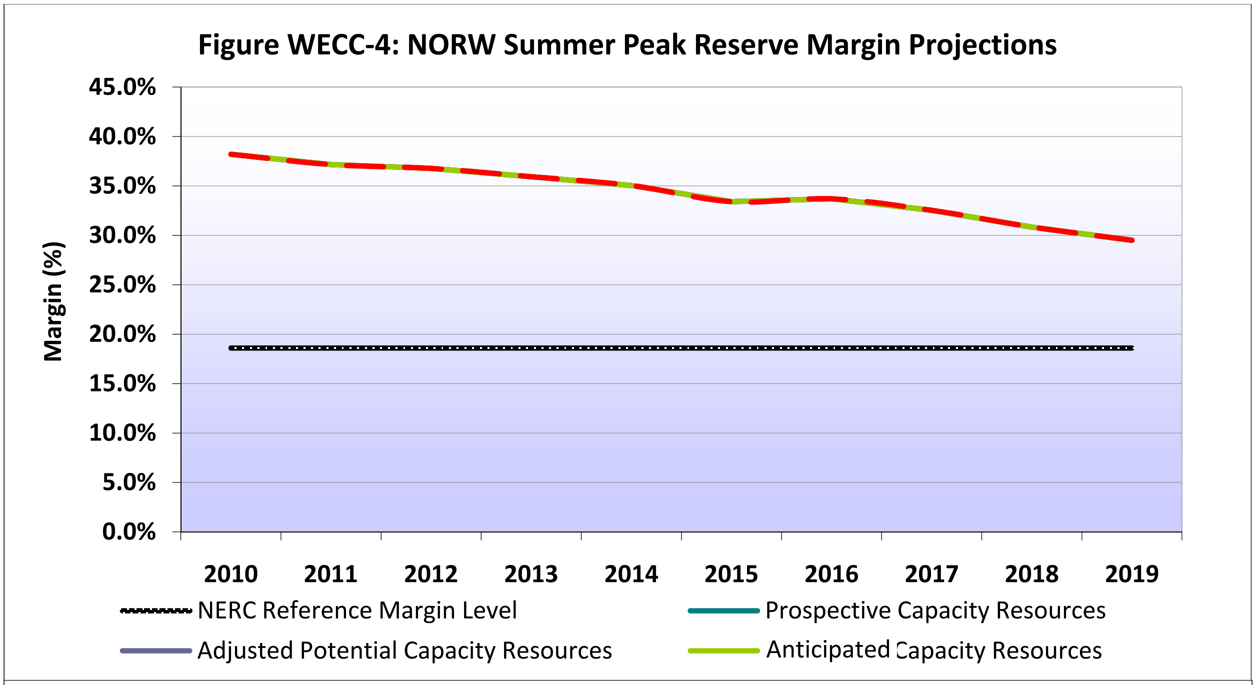
The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -0.1 percent, 8.6 percent, and -2.6 percent, respectively.

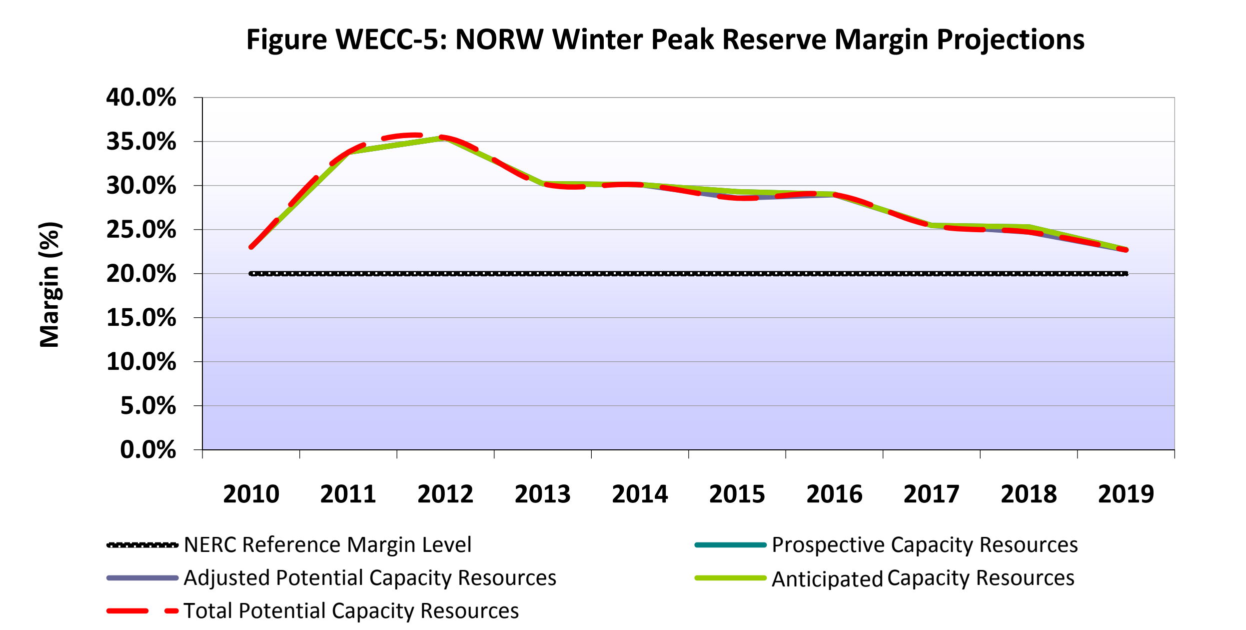
OPERATIONAL ISSUES

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.

RESOURCE ADEQUACY ASSESSMENT

The Northwest subregion target reserve margins are 18.6 percent for the summer and 20.0 percent for the winter. The projected reserve margin does not go below the target margin with the net capacity resources during the assessment period.





Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the Northwest subregion has 3,607 MW, which is derated to 332 MW during the summer peak period.

Table WECC-13: Northwest Existing and Potential Resources (through July 31, 2019)					
	Existing-Certain* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**51,143**	**6,206**	**0**	**0**	**6,206**
Conventional	19,113	237	0	0	237
Hydro	27,894	139	0	0	139
Wind	3,607	5,830	0	0	5,830
Biomass	529	0	0	0	0
Solar	0	0	0	0	0

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-14: Northwest Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected Resources	**37,839**		**1,158**	**0**	**0**	**1,158**
Conventional Projected	13,157		237	0	0	237
Hydro Projected	24,094		107	0	0	107
Wind Projected	332		814	0	0	814
Biomass Projected	256		0	0	0	0
Solar Projected	0		0	0	0	0
Derates or Maintenance		**13,304**	**5,048**	**0**	**0**	**5,048**
Hydro Derate		3,800	32	0	0	32
Wind Derate		3,275	5,016	0	0	5,016
Biomass Derate		273	0	0	0	0
Solar Derate		0	0	0	0	0
Scheduled Outages		5,956	0	0	N/A	0
Confidence Factor				**0%**	**100%**	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

Fuel Supply and Delivery

Wind generation is increasing rapidly in the area. Since the wind resources exhibit fluctuations in output, BAs with relatively large amounts of wind generation are pursuing various processes to optimize integrating growing wind resources into the power grid while maintaining control over essential power system parameters. Careful and site-specific assessments are needed to minimize adverse consequences that may occur.

Transmission Assessment

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-15: Northwest Transmission Line Circuit Miles

Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	12,381	10,402	1,610	5,774	30,167
Under Construction as of 1/1/2010	6	135	0	79	220
Planned - Completed within first five years	77	49	0	68	194
Conceptual - Completed within first five years	5	15	0	0	20
Planned - Completed within second five years	75	0	0	735	810
Conceptual - Completed within second five years	0	10	0	0	10
Total Under Construction and Planned Additions	158	184	0	882	1,224
Total Circuit Miles*	12,544	10,611	1,610	6,656	31,421

**May include projects that are duplicative in nature*

Because of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of accommodating anticipated transfers among 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 882 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 scheme.

Power flow studies have been conducted by the transmission planning authorities and, in 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.

Some BAs are taking steps to help make the transmission queue and transmission queue assessment processes more efficient. For example, BPA has 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.

As noted in the WECC-Canada subregion assessment, preliminary analysis for WECC's 2010 Power Supply Assessment results indicates that transmission constraints occur between the United States and Canada due to economic diversity exchanges.

BASIN (BASN) SUBREGION

PEAK DEMAND AND ENERGY

Basin is a summer-peaking subregion comprised of all or major portions of the states of Idaho, Nevada, Utah, and Wyoming. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 1.9 percent and 2.2 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 2.2 percent.

Table WECC-16: Basin			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	13,054	10,860	76,235
2009 Forecast, Coincident	12,487	9,996	66,588
2009 Actual, Coincident	12,695	11,229	73,449
Growth, Coincident %	-2.8%	3.4%	-3.7%
Deviation from Forecast	1.7%	12.3%	10.3%
2010 Projected, Coincident	13,662	10,633	71,676
Growth, Coincident %	7.6%	-5.3%	-2.4%
2019 Projected, Coincident	16,159	12,880	87,000
2010 – 2019 Growth %	1.9%	2.2%	2.2%

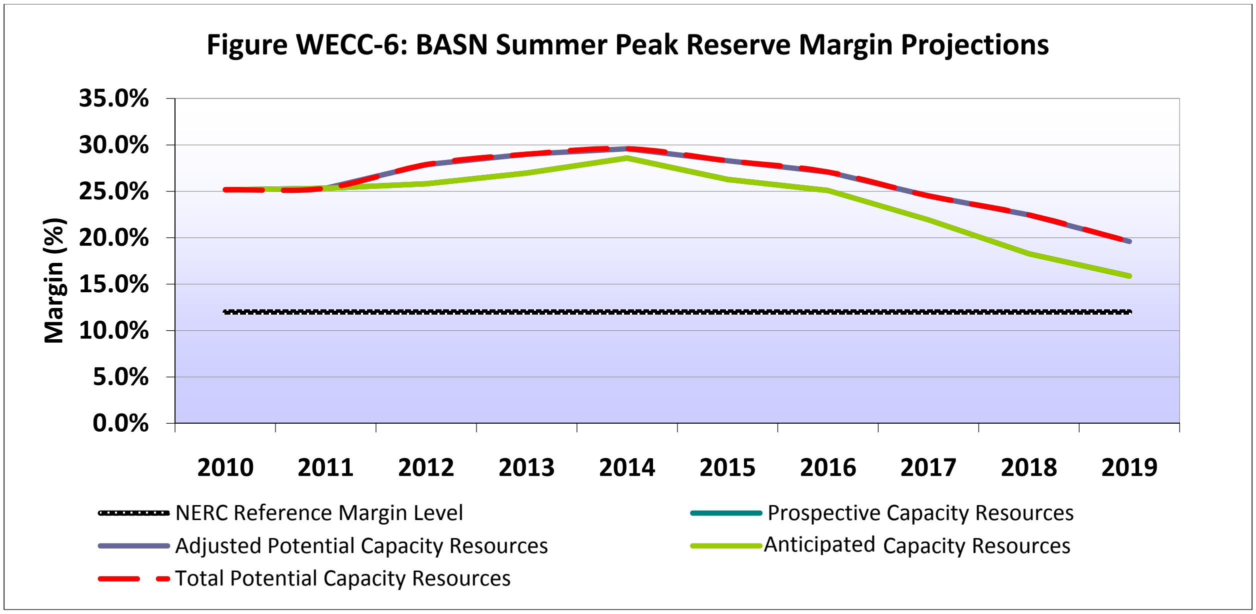
Summer and winter peak demands for the Basin subregion increased by -2.8 percent and 3.4 percent respectively, from 2008 to 2009 while annual energy use increased by -3.7 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by 1.7 percent, 12.3 percent, and 10.3 percent, respectively.

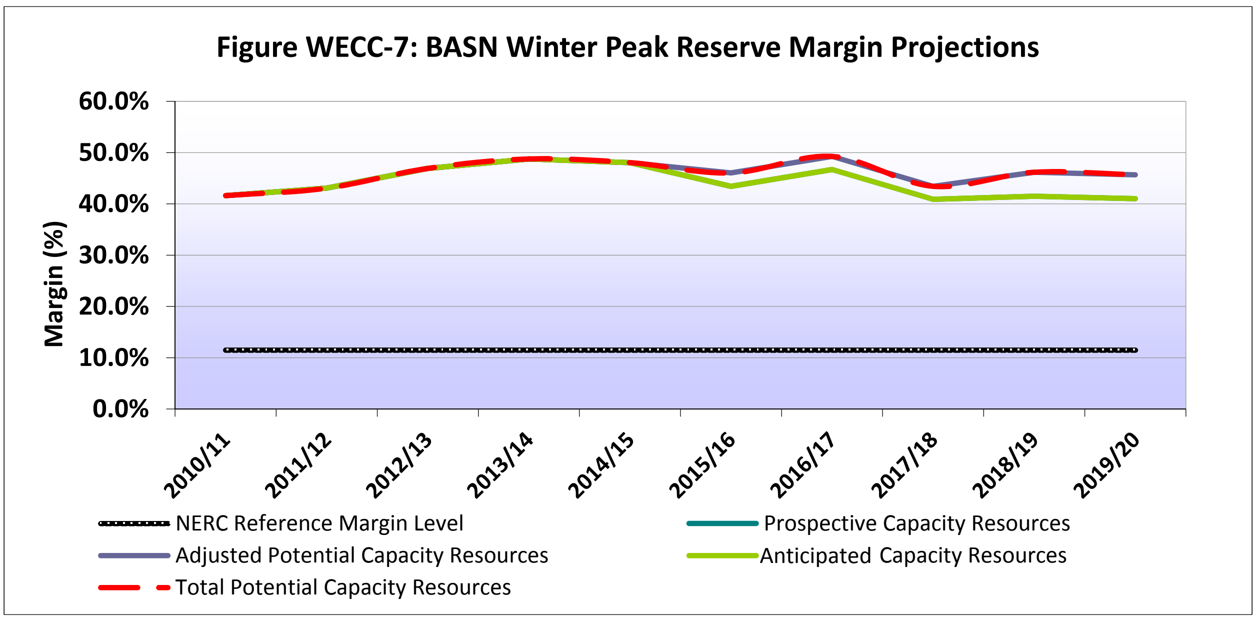
OPERATIONAL ISSUES

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.

RESOURCE ADEQUACY ASSESSMENT

The Basin subregion target reserve margins are 12.0 percent for the summer and 11.5 percent for the winter. The projected reserve margin does not go below the target margin with the net capacity resources during the assessment period.





Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the Basin subregion has 1,009 MW, which is derated to 362 MW during the summer peak period.

Table WECC-17: Basin Existing and Potential Resources (through July 31, 2019)					
	Existing-Certain* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**17,170**	**1,259**	**0**	**755**	**2,014**
Conventional	13,798	579	0	532	1,111
Hydro	2,340	53	0	0	53
Wind	1,009	627	0	223	850
Biomass	23	0	0	0	0
Solar	0	0	0	0	0

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-18: Basin Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected	**15,504**		**648**	**0**	**555**	**1,203**
Conventional Projected	13,768		579	0	532	1,111
Hydro Projected	1,351		28	0	0	28
Wind Projected	362		41	0	23	64
Biomass Projected	23		0	0	0	0
Solar Projected	0		0	0	0	0
Derates or Maintenance		**1,666**	**611**	**0**	**200**	**811**
Hydro Derate		989	25	0	0	25
Wind Derate		647	586	0	200	786
Biomass Derate		0	0	0	0	0
Solar Derate		0	0	0	0	0
Scheduled Outages		30	0	0	N/A	0
Confidence Factor				**0%**	**100%**	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

Fuel Supply and Delivery

Coal-fired generation in the area is prevalent. Much of the coal-fired generation is near the fuel sources and is generally operated in a base-load mode. Consequently, the area is not highly reliant on gas-fired plants relative to annual energy generation and many of those plants are operated as seasonal peaking units.

Transmission Assessment

The following table presents the existing transmission mileage and the planned transmission additions mileage for the assessment period.

Table WECC-19: Basin Transmission Line Circuit Miles

Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	5,829	3,784	2,792	358	12,763
Under Construction as of 1/1/2010	0	44	145	0	189
Planned - Completed within first five years	46	94	373	995	1,508
Conceptual - Completed within first five years	0	0	0	280	280
Planned - Completed within second five years	3	261	190	1,837	2,291
Conceptual - Completed within second five years	0	14	-84	1,013	943
Total Under Construction and Planned Additions	49	399	708	2,832	3,988
Total Circuit Miles*	5,878	4,197	3,416	4,483	17,974

**May include projects that are duplicative in nature*

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.

ROCKIES (ROCK) SUBREGION

PEAK DEMAND AND ENERGY

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. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 2.4 percent and 2.1 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 1.8 percent.

Table WECC-20: Rockies

	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	11,584	10,299	65,129
2009 Forecast, Coincident	12,127	10,439	67,662
2009 Actual, Coincident	10,565	10,177	63,329
Growth, Coincident %	-8.8%	-1.2%	-2.8%
Deviation from Forecast	-12.9%	-2.5%	-6.4%
2010 Projected, Coincident	10,979	9,795	66,565
Growth, Coincident %	3.9%	-3.8%	5.1%
2019 Projected, Coincident	13,642	11,805	77,866
2010 – 2019 Growth %	2.4%	2.1%	1.8%

Summer and winter peak demands for the Rockies subregion increased by -8.8 percent and -1.2 percent respectively, from 2008 to 2009 while annual energy use increased by -2.8 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -12.9 percent, -2.5 percent, and -6.4 percent, respectively.

RESOURCE ADEQUACY ASSESSMENT

The Rockies subregion target reserve margins are 12.3 percent for the summer and 13.5 percent for the winter. The projected reserve margins do not fall below the target margins during the assessment period.

Figure WECC-8: ROCK Summer Peak Reserve Margin Projections

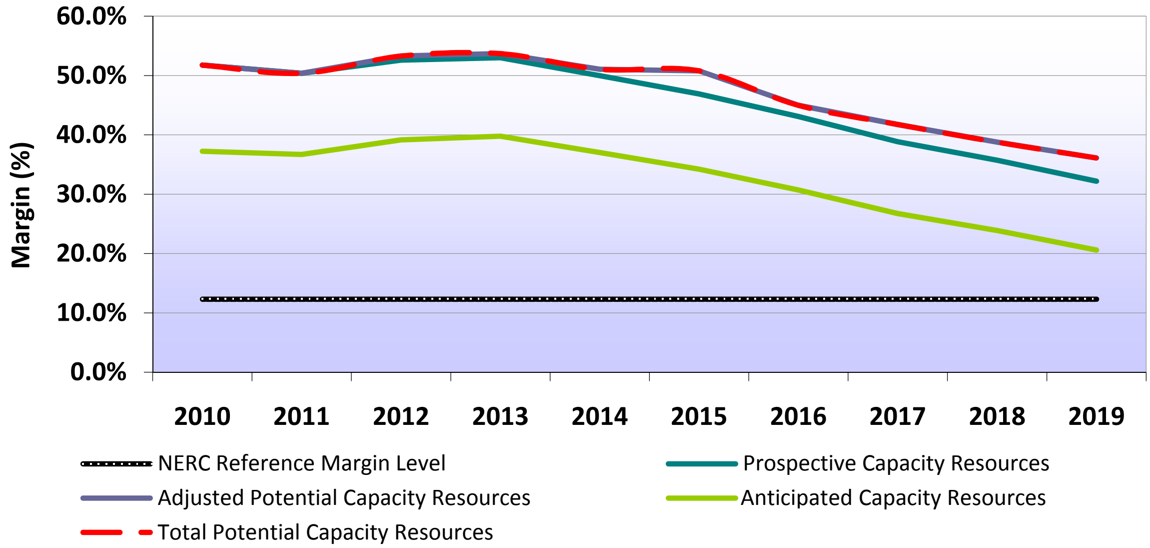
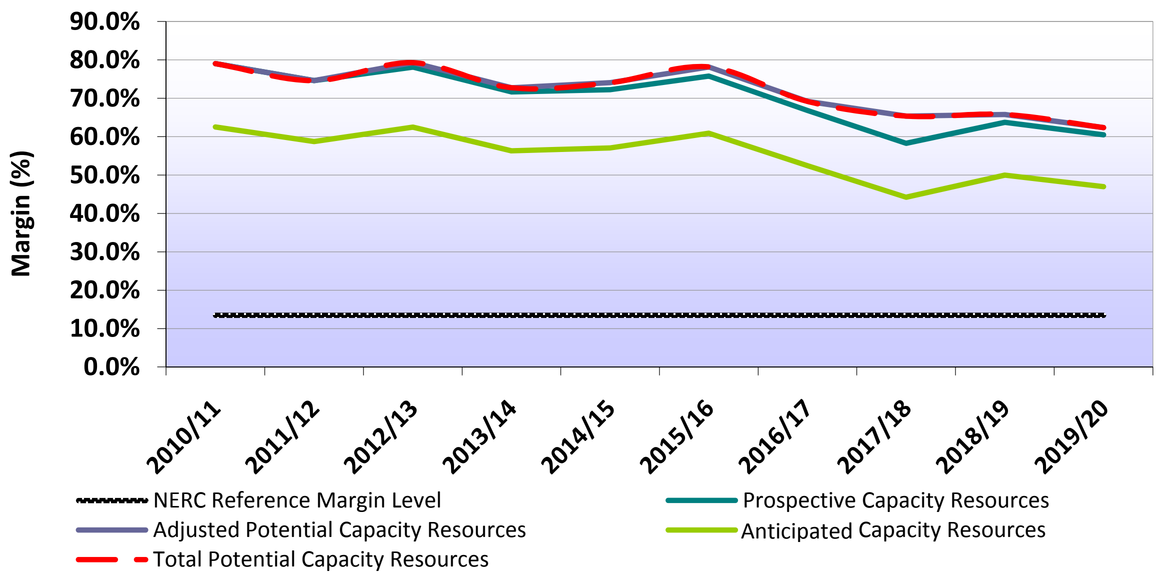


Figure WECC-9: ROCK Winter Peak Reserve Margin Projections



Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the Rockies subregion has 1,109 MW, which is derated to 188 MW during the summer peak period.

Table WECC-21: Rockies Existing and Potential Resources (through July 31, 2019)					
	Existing* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**15,909**	**832**	**0**	**290**	**1,122**
Conventional	13,336	764	0	80	844
Hydro	1,453	0	0	0	0
Wind	1,109	51	0	206	257
Biomass	3	0	0	0	0
Solar	8	17	0	4	21

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-22: Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain * (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected Resources	**14,368**		**810**	**0**	**158**	**968**
Conventional Projected	13,178		764	0	80	844
Hydro Projected	998		0	0	0	0
Wind Projected	188		46	0	75	121
Biomass Projected	0		0	0	0	0
Solar Projected	4		0	0	3	3
Derates or Maintenance		**1,541**	**22**	**0**	**132**	**154**
Hydro Derate		455	0	0	0	0
Wind Derate		921	5	0	131	136
Biomass Derate		3	0	0	0	0
Solar Derate		4	17	0	1	18
Scheduled Outages		158	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

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 plan procedures or some other similar process.

Fuel Supply and Delivery

Coal, hydro, and gas-fired plants are the dominant electricity sources in the area. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants may experience operational limitations due to variations in precipitation. As in the Northwest, gas-fired plants are most often operated in a peaking mode. Abundant natural gas supplies exist within the area but delivery constraints may occur at some plants during unexpected severe cold weather conditions.

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 was completed in late 2006 and concluded that a reasonable capacity value for wind was 12.5 percent of nameplate capacity. The solar ELCC was filed with the Colorado PUC in December 2008. The study concluded that the reasonable capacity value for solar varies between 60 and 80 percent depending on the location and type of solar resource. The PSCo uses a 70 percent capacity value for their solar resources.

Transmission Assessment

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-23: Rockies Transmission Line Circuit Miles

Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	6,130	5,296	982	0	12,408
Under Construction as of 1/1/2010	124	114	0	0	238
Planned - Completed within first five years	170	347	221	0	738
Conceptual - Completed within first five years	0	0	0	0	0
Planned - Completed within second five years	174	65	0	0	239
Conceptual - Completed within second five years	45	0	0	0	45
Total Under Construction and Planned Additions	468	526	221	0	1,215
Total Circuit Miles	6,643	5,822	1,203	0	13,668

**May include projects that are duplicative in nature*

There are currently 526 miles of 200-299 kV transmission lines and 221 miles of 300-399 kV transmissions lines that are under construction or planned for construction within the next ten years in the Rockies subregion.

Tri-State Generation and Transmission is proposing a project in southern Colorado called the San Luis Valley Electric System Improvement project. The project would involve the construction of an 80 mile 230 kV transmission line between the Walsenburg Substation and the San Luis Valley Substation. The San Luis Valley's existing electrical system has reached its limit due to continued residential and irrigation growth. One major concern is the radial nature of the existing 230 kV transmission system does not provide the reliability benefits of redundant service. The other major problem currently experienced on the transmission system is a drop in voltage that occurs when the load on the electric system in the valley is above 65 MW. This line will provide the power delivery infrastructure to increase the reliability and capacity of the existing transmission system and support proposed renewable energy development in the area.

The Western Area Power Administration (WAPA) 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. In addition to those conversions, the table at the end of WECC's self-assessment describes additional transmission projects.

Operational Issues

Transmission upgrades in the area have alleviated some transfer capability limitations, but some system constraints remain. Operator flexibility will be limited by the transmission constraints and operating conditions must be closely monitored, especially during periods of high demand. In some cases, special protection schemes are used to preserve system adequacy, should multiple outage contingencies occur.

DESERT SOUTHWEST (DSW) SUBREGION

PEAK DEMAND AND ENERGY

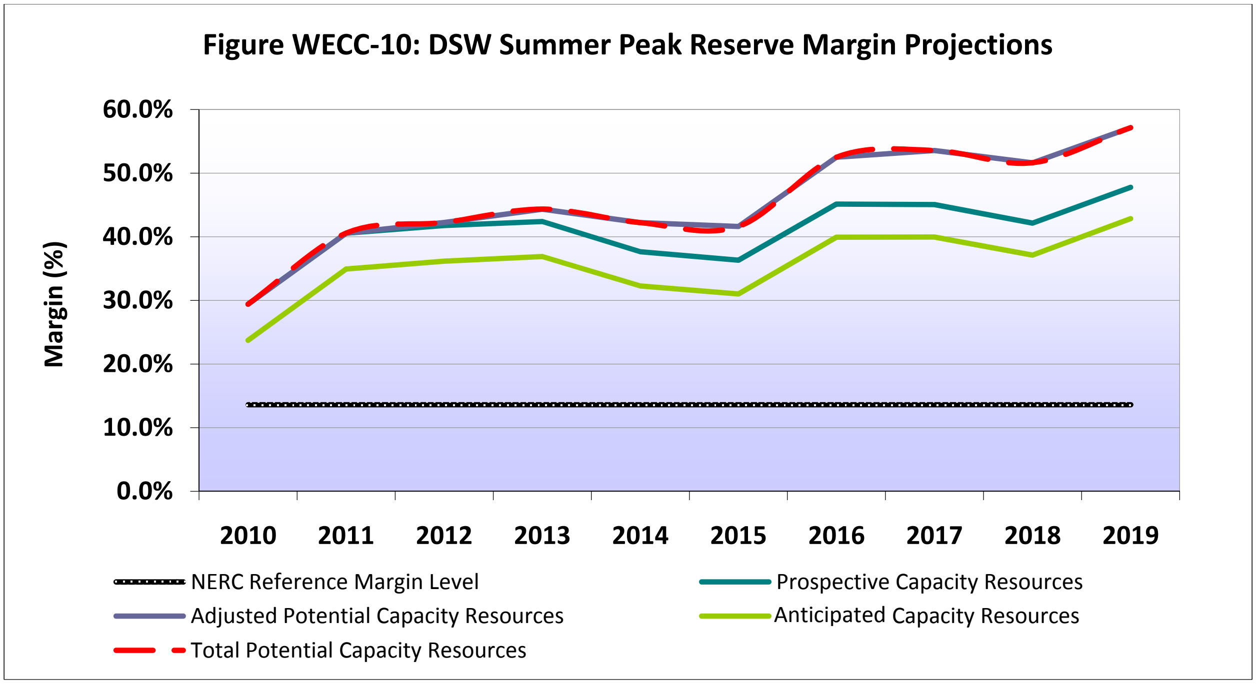
The Desert Southwest subregion consists of Arizona, most of New Mexico, southern Nevada, and the westernmost part of Texas. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 1.7 percent and 1.8 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 2.0 percent.

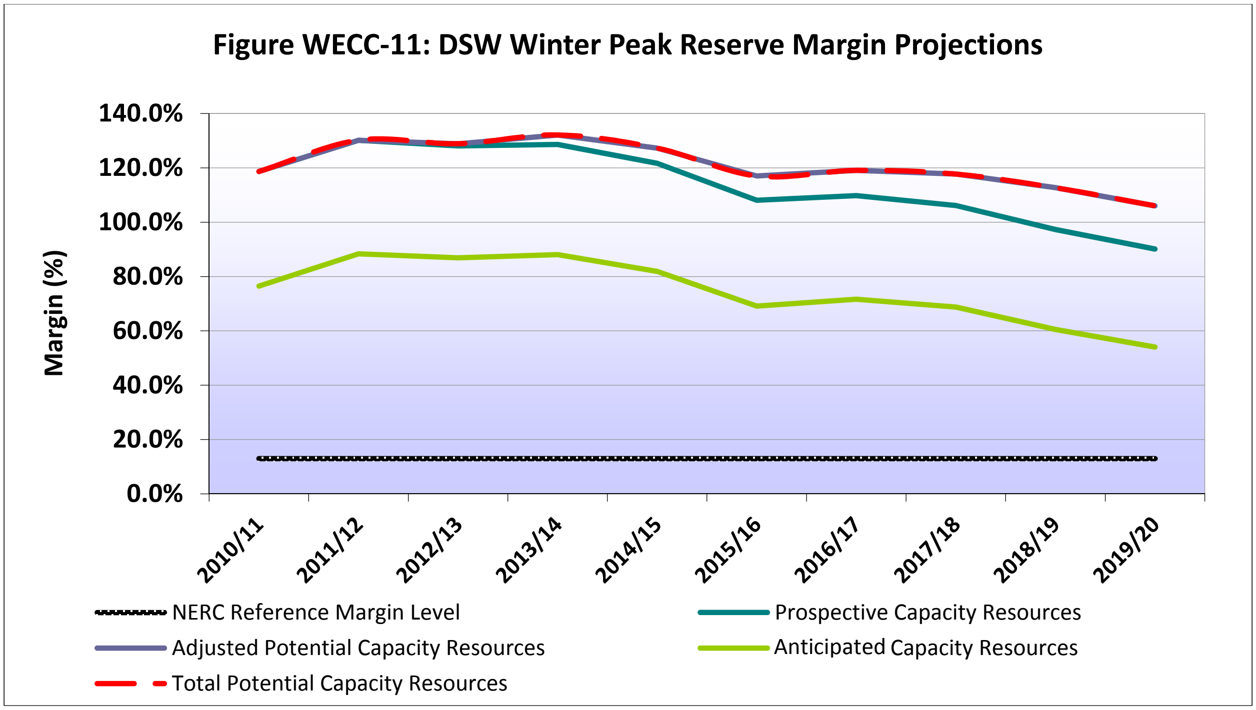
Table WECC-24: Desert Southwest			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	27,629	16,752	133,038
2009 Forecast, Coincident	29,843	18,128	140,254
2009 Actual, Coincident	27,968	16,483	129,602
Growth, Coincident %	1.2%	-1.6%	-2.6%
Deviation from Forecast	-6.3%	-9.1%	-7.6%
2010 Projected, Coincident	27,997	17,253	133,143
Growth, Coincident %	0.1%	4.7%	2.7%
2019 Projected, Coincident	32,552	20,253	159,443
2010 – 2019 Growth %	1.7%	1.8%	2.0%

Summer and winter peak demands for the Desert Southwest subregion increased by 1.2 percent and -1.6 percent respectively, from 2008 to 2009 while annual energy use increased by -2.6 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -6.3 percent, -9.1 percent, and -7.6 percent, respectively.

RESOURCE ADEQUACY ASSESSMENT

The Desert Southwest subregion target reserve margins are 13.6 percent for the summer and 13.0 percent for the winter. The projected reserve margins do not fall below the target reserve margins during the assessment period.





Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the Desert Southwest subregion has 299 MW, which is derated to 90 MW during the summer peak period.

Table WECC-25: Desert Southwest Existing and Potential Resources (through July 31, 2019)					
	Existing* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**40,343**	**3,361**	**0**	**3,593**	**6,954**
Conventional	36,443	2,622	0	2,311	4,933
Hydro	3,474	0	0	0	0
Wind	299	0	0	614	614
Biomass	31	0	0	8	8
Solar	96	739	0	660	1,399

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-26: Desert Southwest Existing and Adjusted Resources						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected	38,787		3,322	0	2,973	6,295
Conventional Projected	35,258		2,622	0	2,311	4,933
Hydro Projected	3,366		0	0	0	0
Wind Projected	90		0	0	44	44
Biomass Projected	24		0	0	8	8
Solar Projected	49		700	0	610	1,310
Derates or Maintenance		1,556	39	0	620	659
Hydro Derate		108	0	0	0	0
Wind Derate		209	0	0	570	570
Biomass Derate		7	0	0	0	0
Solar Derate		47	39	0	50	89
Scheduled Outages		1,185	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

In Arizona, the renewable portfolio is a set of financial incentives from a large number of programs.[227] The RPS that Salt River Project (SRP) is responsive to is the Sustainable Portfolio Principles established by the SRP Board in 2004, and revised in 2006. These principles direct 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 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[228] and rules requiring that investor-owned utilities meet the 20 percent by 2020 target through a "fully diversified renewable energy portfolio" which is defined as a minimum of 20 percent solar power, 20 percent wind power, and 10 percent from either biomass or geothermal energy starting in 2011. Additionally 1.5 percent must come from distributed renewables by 2011, rising to three percent in 2015.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in this area will depend on how much new capacity is actually constructed. Frequently, resource acquisitions, including load-reduction options, are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc. These factors combine to make resource adequacy forecasting problematic over an extended period of time.

The subregion has not established a process for assessing resource adequacy. However, individual entities within the subregion have addressed resource adequacy as a part of either their integrated resource planning process or other similar process.

Fuel Supply and Delivery

Coal, hydro, and nuclear plants are the dominant electricity sources in the area. Gas-fired plants are most often operated in a peaking mode. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Major hydroelectric plants are located at dams with significant storage capability, so short-term variations in precipitation are not a significant factor in fuel planning.

Transmission Assessment

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

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[227] Arizona Incentives/Policies for Renewables & Efficiency

[228] http://www.nmprc.state.nm.us/renewable.htm

Table WECC-27: Desert Southwest Transmission Line Circuit Miles					
Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	4,846	3,456	4,465	2,282	15,049
Under Construction as of 1/1/2010	25	0	0	1	26
Planned - Completed within first five years	29	268	0	832	1,129
Conceptual - Completed within first five years	92	20	0	695	807
Planned - Completed within second five years	0	71	0	56	127
Conceptual - Completed within second five years	93	118	42	0	253
Total Under Construction and Planned Additions	54	339	0	889	1,282
Total Circuit Miles*	5,085	3,933	4,507	3,866	17,391

**May include projects that are duplicative in nature*

Transmission providers from DSW, along with other stakeholders from southern California, are actively engaged in the Southwest Transmission Expansion Planning (STEP) group. The goal of this group is to collaborate in the planning, coordination, and implementation of a robust transmission system 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.

Operational Issues

Special protection schemes play an important role in maintaining system adequacy should multiple system outages occur. These schemes include generator tripping in response to specific transmission line outages. In addition, operators rely on procedures such as operating nomograms so the system can respond adequately to planned and unplanned transmission or generation outages.

California North and South (CALN and CALS)

Peak Demand and Energy

Due to a significant internal bulk power system transfer capability constraint, WECC's Power Supply Assessment studies and transmission expansion planning studies divide California into northern and southern areas. The northern portion is referred to in this assessment as California-North while the southern portion is identified as California-South. Two BAs operate solely in CALN and two more operate solely in CALS, but the California ISO (CAISO) BA operates in both subregions. Due to the overlap of the CAISO operations, statewide regulatory jurisdictions, and other common factors, this assessment addresses CALN and CALS common issues in this California Discussion section. Separate CALN and CALS presentations follow this aggregated discussion.

For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 0.8 percent and 1.2 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 1.2 percent.

Table WECC-28: California Total

	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	58,840	41,832	295,999
2009 Forecast, Coincident	61,238	41,922	296,368
2009 Actual, Coincident	57,439	41,075	285,913
Growth, Coincident %	-2.4%	-1.8%	-3.4%
Deviation from Forecast	-6.2%	-2.0%	-3.5%
2010 Projected, Coincident	57,609	40,648	289,887
Growth, Coincident %	0.3%	-1.0%	1.4%
2019 Projected, Coincident	61,751	45,106	321,649
2010 – 2019 Growth %	0.8%	1.2%	1.2%

Summer and winter peak demands for California increased by -2.4 percent and -1.8 percent respectively, from 2008 to 2009 while annual energy use increased by -3.4 percent.

The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -6.2 percent, -2.0 percent, and -3.5 percent, respectively.

Resource Adequacy Assessment

The aggregate California target reserve margins are 14.8 percent for the summer and 11.4 percent for the winter. The projected reserve margins do not fall below the target reserve margins during the assessment period.

Figure WECC-12: California Summer Peak Reserve Margin Projections

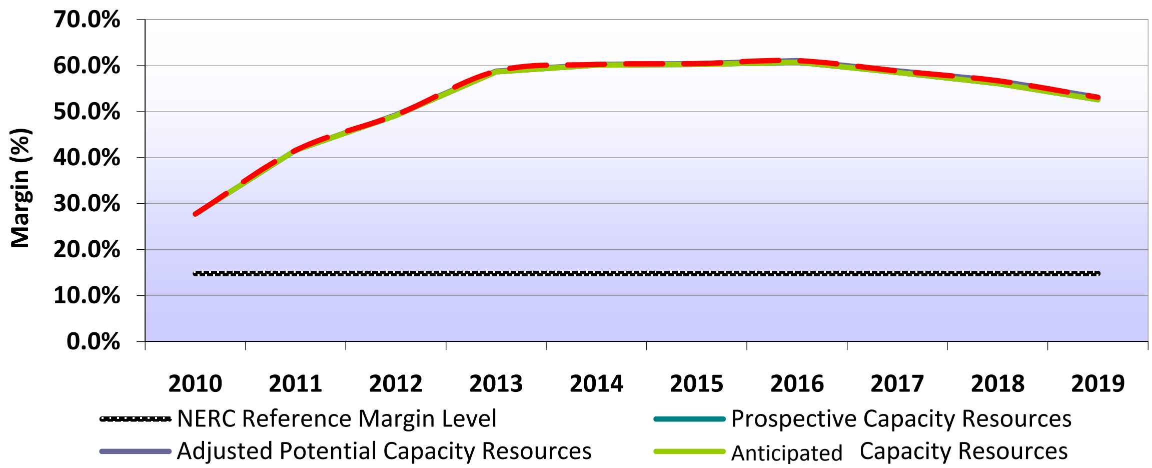
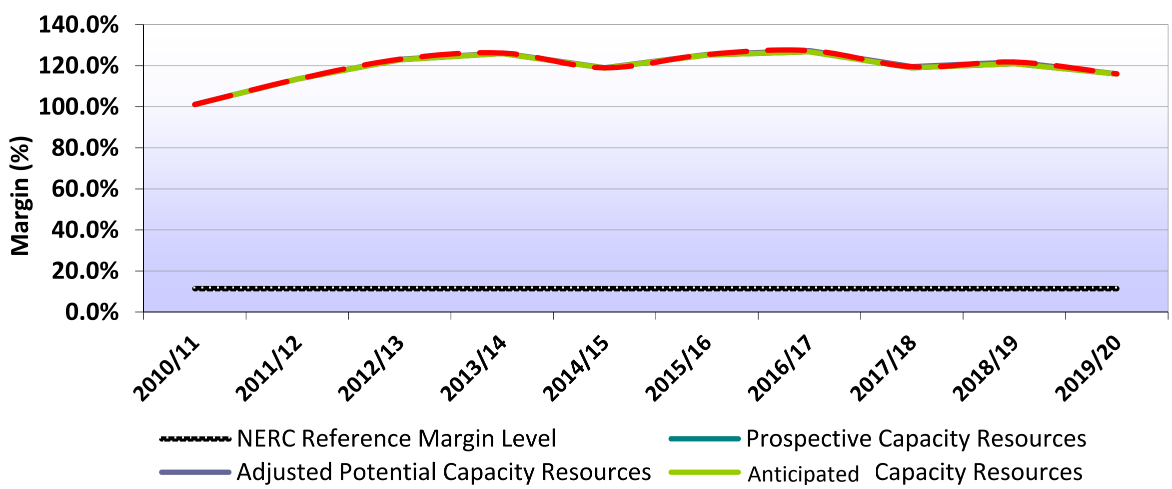


Figure WECC-13: California Winter Peak Reserve Margin Projections



This picture of projected margins cannot portray the dilemma of knowing whether all of the proposed resources are deliverable to load in the timeframes proposed by the project proponents. In-depth transmission interconnection assessments and more aggregate planning studies are underway to discern the transmission requirements associated with proposed projects. The results of these studies may affect the confidence factors associated with specific projects in future *Long-Term Reliability Assessment* cycles.

Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the California area has 3,261 MW, which is derated to 55 MW during the summer peak period.

Table WECC-29: California Existing and Potential Resources (through July 31, 2019)					
	Existing* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**70,556**	**37,663**	**0**	**465**	**38,128**
Conventional	54,972	15,051	0	295	15,346
Hydro	10,825	347	0	0	347
Wind	3,261	10,549	0	170	10,719
Biomass	1,060	110	0	0	110
Solar	438	11,606	0	0	11,606

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-30: California Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected	55,185		26,427	0	353	26,780
Conventional	46,730		15,051	0	295	15,346
Hydro Projected	7,603		220	0	0	220
Wind Projected	55		173	0	58	231
Biomass Projected	359		110	0	0	110
Solar Projected	438		10,873	0	0	10,873
Derates or Maintenance		15,371	11,236	0	112	11,348
Hydro Derate		3,222	127	0	0	127
Wind Derate		3,206	10,376	0	112	10,488
Biomass Derate		701	0	0	0	0
Solar Derate		0	733	0	0	733
Scheduled Outages		8,242	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

In June of 2006, California passed Assembly Bill 32, *the California Global Warming Solutions Act of 2006*, which had a significant influence on how California plans to meet its future needs and cap California's greenhouse gas emissions at the 1990 level by 2020. On December 5, 2007, California adopted the *2007 Integrated Energy Policy Report*[229] which states that "Scenario analysis indicates that these aggressive cost-effective efficiency programs, when coupled with renewables development, could allow the electricity industry to achieve at least a proportional reduction, and perhaps more, of the state's CO_2 emissions to meet AB 32's 2020 goals"

California has an RPS statute requiring LSEs to achieve 20 percent renewable energy by 2010. There is an Executive order by Governor Schwarzenegger, and legislative proposals, to revise the RPS to require 33 percent by 2020. The CEC determines the Net Qualifying Capacity of renewable resources by using formulas established by the California Public Utilities Commission (CPUC) for its jurisdictional entities (matched by the California's ISO (CAISO) tariff requirements for public utilities in its balancing authority area) for determining the capacity contribution of variable resources. CAISO also publishes the monthly wind contribution factors[230] that they use with their resources and has worked to develop solutions to the integration of large amounts of renewable resources[231] within their BA area.

The CPUC has an established a year-ahead and monthly system Resource Adequacy Requirement[232] (RAR) for LSEs under the CPUS's jurisdiction. The RAR requires LSEs to make a year-ahead system and local RAR compliance filing that demonstrates compliance with the 90 percent of system RAR obligation for the five summer months of May through September, as well as 100 percent of the local RAR for all 12 months, by the end of October. Direct Control Load Management products are included as resources to meet the LSE's RAR.

The portions of California under the jurisdiction of the CPUC employ a mandatory resource adequacy program requiring LSEs to procure 115 percent of their forecast peak demand for each month. Non-CPUC jurisdictional utilities in the CAISO BA area are allowed, by CAISO tariff, to set their own planning Reserve Margin values. Although, most use 115 percent, some do not. The smaller BAs in California have their own planning standards that do not parallel those established collectively for the CAISO BA by the CPUC and CAISO. State entities are working together, and with other entities in the Western Interconnection, to address transmission planning issues.

Fuel Supply and Delivery

California is highly reliant on gas-fired generation and has very little alternate fuel capability for these plants. In February 2008, the California Energy Commission produced the *2008 Update to the Energy Action Plan* (UEAP)[233] and on page 16, begins to address the natural gas supply, demand, and

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229 CEC's Integrated Energy Policy Report

230 CAISO's Wind Contribution Factors

231 CAISO's Integration of Renewable Resources Program

232 CPUC's Resource Adequacy Web site

233 CEC 2008 Energy Action Plan

infrastructure and states they will: 1) Continue to monitor and assess the gas market and its impact on California consumers; 2) Examine whether and how California utilities should enter into contracts for liquefied natural gas supplies; and 3) Ensure that California has adequate access to those supplies. The UEAP also mentions that there have been proposals for the expansion of gas storage capacities and for a significant expansion of pipeline capacity from the Rocky Mountains to California, and that they will be assessing those projects.

Transmission Assessment

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-31: California Transmission Line Circuit Miles

Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	9,409	12,669	101	4,340	26,519
Under Construction as of 1/1/2010	41	288	0	91	420
Planned - Completed within first five years	279	171	0	333	783
Conceptual - Completed within first five years	0	569	0	272	841
Planned - Completed within second five years	0	0	0	0	0
Conceptual - Completed within second five years	0	23	0	3,120	3,143
Total Under Construction and Planned Additions	320	459	0	424	1,203
Total Circuit Miles*	9,729	13,720	101	8,156	31,706

**May include projects that are duplicative in nature*

With California's new energy policies that require substantial increases in the generation of electricity from renewable energy resources, implementation of these policies will require extensive improvements to California's electric transmission infrastructure. California has developed the Renewable Energy Transmission Initiative[234] which is a statewide initiative to help identify the transmission projects needed to accommodate California's renewable energy goals, facilitate transmission corridor designation, and facilitate transmission and generation citing permitting.

As mentioned earlier, with the Arizona Corporation Commission's May 2007 denial of SCE's Palo Verde – Devers #2 (PVD2) permit, in May 2009 Southern California Edison (SCE) dropped the Arizona portion of the proposed line and announced that it would proceed to construct the California portion in 2010.

[234] CEC's Renewable Energy Transmission Initiative

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.

Special protection schemes have been implemented for generation connected to the Imperial Valley substation in order to relieve some of the congestion and an operating nomogram is used to limit the simultaneous operation of generating plants connected to the Imperial Valley substation and imports from Comisión Federal de Electricidad and Arizona.

Operational Issues

The CAISO has implemented its Market Redesign and Technology Upgrade (MRTU) program, which makes several changes to ISO market and grid operations. The CAISO implemented the MRTU April 1, 2009, which includes upgrades to the CAISO's computer technology to a scalable system that can grow and adapt to future system requirements. Transmission upgrades in the area have alleviated some transfer capability limitations, but numerous system constraints remain.

Over the past decade, the U.S. Environmental Protection Agency is readdressing the Clean Water Act Section 316(b) Phase II, which pertains of once-through-cooling on existing power plants. The once-through-cooling process uses water from a river or ocean for condensing low-pressure steam to water as part of the thermal cycle of these units. In January 2007, the Second Circuit Court issued its decision (Decision) on the Phase II Rule litigation. The result of that Decision was to demand significant portions of the previous EPA 316 b rule back to the EPA. As a result, the EPA withdrew the Phase II Rule in its entirety and directed EPA Regions and states to implement §316(b) on a Best Professional Judgment (BPJ) basis until the litigation issues are resolved. Within the State of California, there are 19 thermal generating plants that use once-through-cooling technology, using large amounts of ocean or estuarial water. Pursuant to the U.S. EPA BPJ directive, the California State Water Resources Control Board is also considering a proposal[235] that would require these units to stop or greatly reduce the amount of ocean or estuarial water they use in the cooling process in order to minimize the intake and mortality of marine life.

[235] California State Water Board Policy

California-North (CALN) subregion

Peak Demand and Energy

The California-North subregion encompasses the portion of California served by the Sacramento Municipal Utility District BA, the Turlock Irrigation District BA, and the portion of the California Independent System Operator BA encompassing the Pacific Gas & Electric Company electric transmission grid. This area is also known as the North of Path 26 area. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 0.9 percent and 1.2 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 1.1 percent.

Table WECC-32: California-North

	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	27,021	18,155	128,119
2009 Forecast, Coincident	27,534	18,476	128,687
2009 Actual, Coincident	24,532	18,251	124,405
Growth, Coincident %	-9.2%	0.5%	-2.9%
Deviation from Forecast	-10.9%	-1.2%	-3.3%
2010 Projected, Coincident	25,310	18,088	127,092
Growth, Coincident %	3.2%	-0.9%	2.2%
2019 Projected, Coincident	27,502	20,177	140,378
2010 – 2019 Growth %	0.9%	1.2%	1.1%

Summer and winter peak demands for the California-North subregion increased by -9.2 percent and 0.5 percent respectively, from 2008 to 2009 while annual energy use increased by -2.9 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -10.9 percent, -1.2 percent, and -3.3 percent, respectively.

Resource Adequacy Assessment

The California-North subregion target reserve margins are 14.6 percent for the summer and 10.5 percent for the winter. The projected reserve margins do not fall below the target reserve margins during the assessment period.

Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the California-North subregion has 1,722 MW, which is derated to 32 MW during the summer peak period.

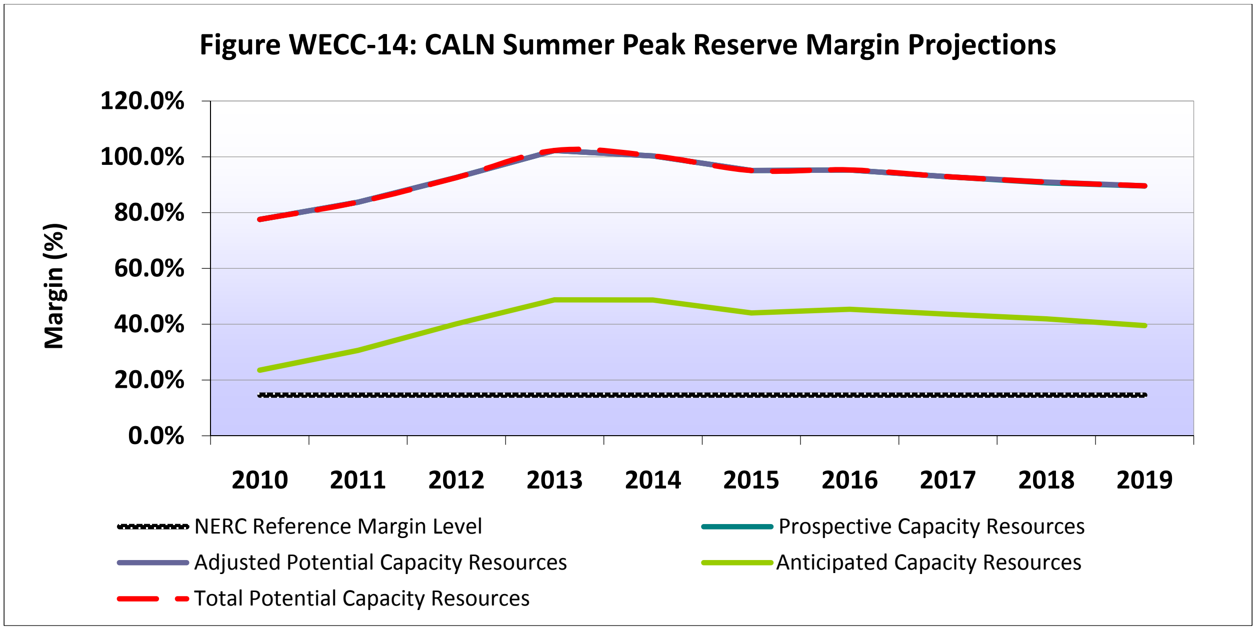


Figure WECC-14: CALN Summer Peak Reserve Margin Projections
Margin (%)
120.0%
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
NERC Reference Margin Level
Prospective Capacity Resources
Adjusted Potential Capacity Resources
Anticipated Capacity Resources
Total Potential Capacity Resources

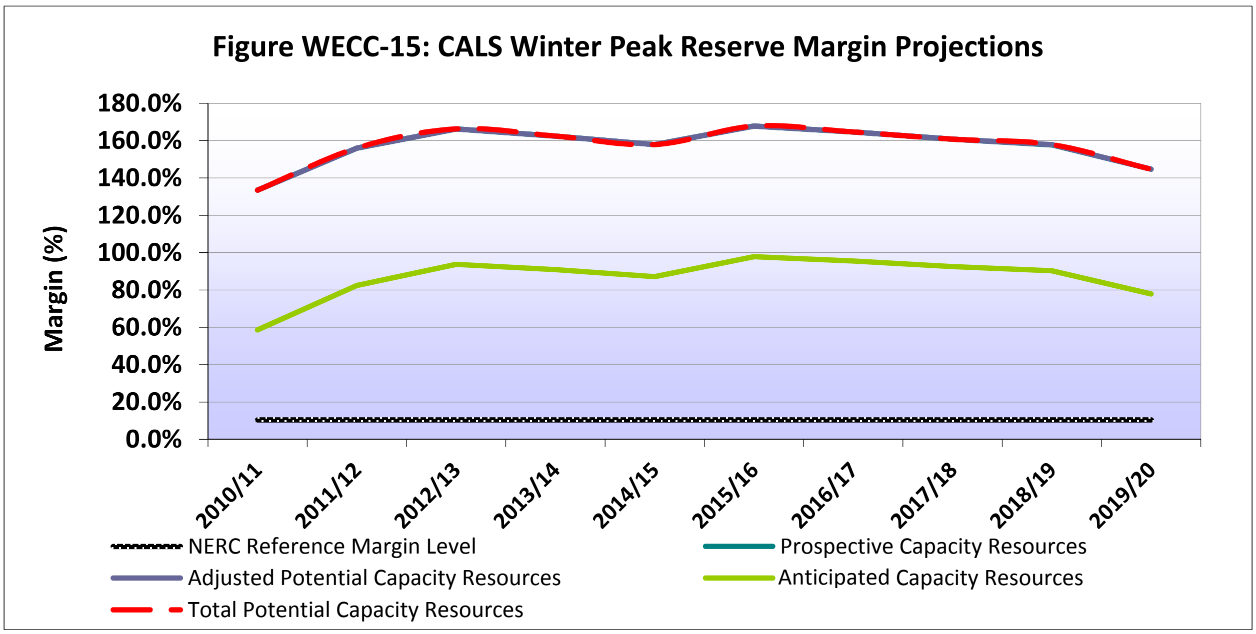


Figure WECC-15: CALS Winter Peak Reserve Margin Projections
Margin (%)
180.0%
160.0%
140.0%
120.0%
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
NERC Reference Margin Level
Prospective Capacity Resources
Adjusted Potential Capacity Resources
Anticipated Capacity Resources
Total Potential Capacity Resources

Table WECC-33: California-North Existing and Potential Resources (through July 31, 2019)					
	Existing-Certain* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**39,726**	**9,559**	**0**	**170**	**9,729**
Conventional	28,606	6,975	0	0	6,975
Hydro	8,685	0	0	0	0
Wind	1,722	797	0	170	967
Biomass	708	61	0	0	61
Solar	5	1,726	0	0	1,726

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-34: California-North Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected	26,491		8,956	0	41	8,997
Conventional Projected	20,602		6,975	0	0	6,975
Hydro Projected	5,610		0	0	0	0
Wind Projected	32		194	0	41	235
Biomass Projected	242		61	0	0	61
Solar Projected	5		1,726	0	0	1,726
Derates or Maintenance		13,235	603	0	129	732
Hydro Derate		3,075	0	0	0	0
Wind Derate		1,690	603	0	129	732
Biomass Derate		466	0	0	0	0
Solar Derate		0	0	0	0	0
Scheduled Outages		8,004	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

TRANSMISSION ASSESSMENT

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-35: California-North Transmission Line Circuit Miles					
Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	6,700	6,990	0	1,841	15,531
Under Construction as of 1/1/2010	41	155	0	0	196
Planned - Completed within first five years	279	94	0	0	373
Conceptual - Completed within first five years	0	350	0	0	350
Planned - Completed within second five years	0	0	0	0	0
Conceptual - Completed within second five years	0	8	0	2,780	2,788
Total Under Construction and Planned Additions	320	249	0	0	569
Total Circuit Miles*	7,020	7,597	0	4,621	19,238

**May include projects that are duplicative in nature*

California-South (CALS) subregion

Peak Demand and Energy

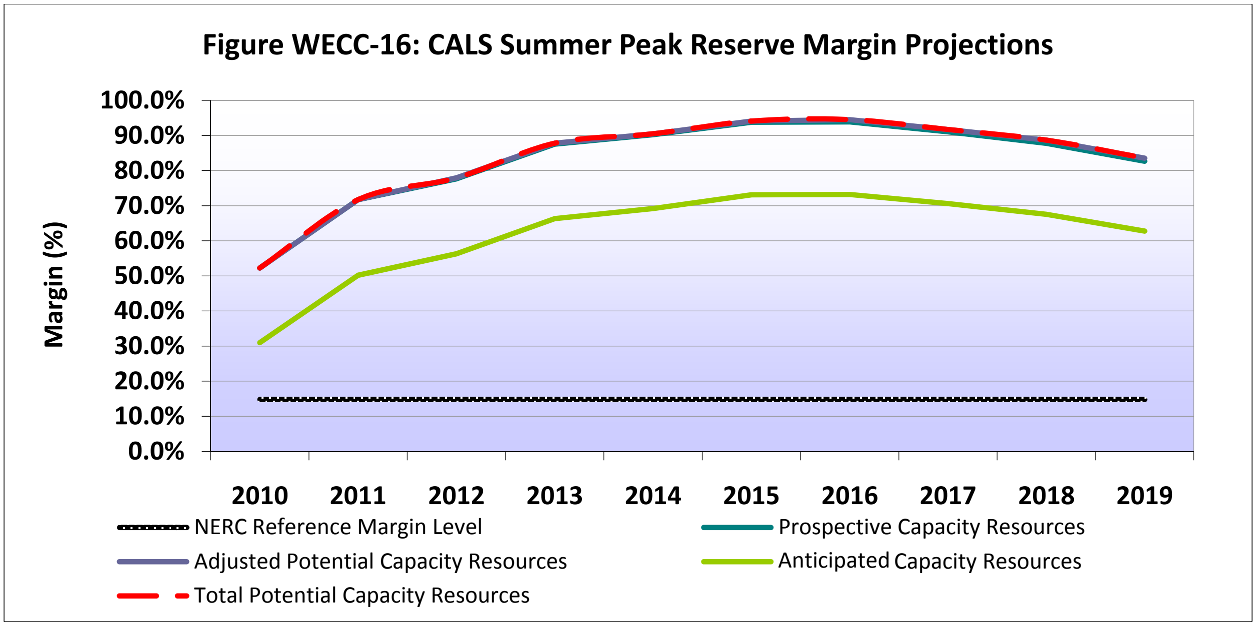
The California-South area encompasses the portion of California served by the Imperial Irrigation District BA, the Los Angeles Department of Water and Power BA, and the portion of the California Independent System Operator BA encompassing the San Diego Gas and Electric Company and Southern California Edison Company electric transmission grids. This area is also known as the South of Path 26 area. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 1.2 percent and 1.2 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 1.2 percent.

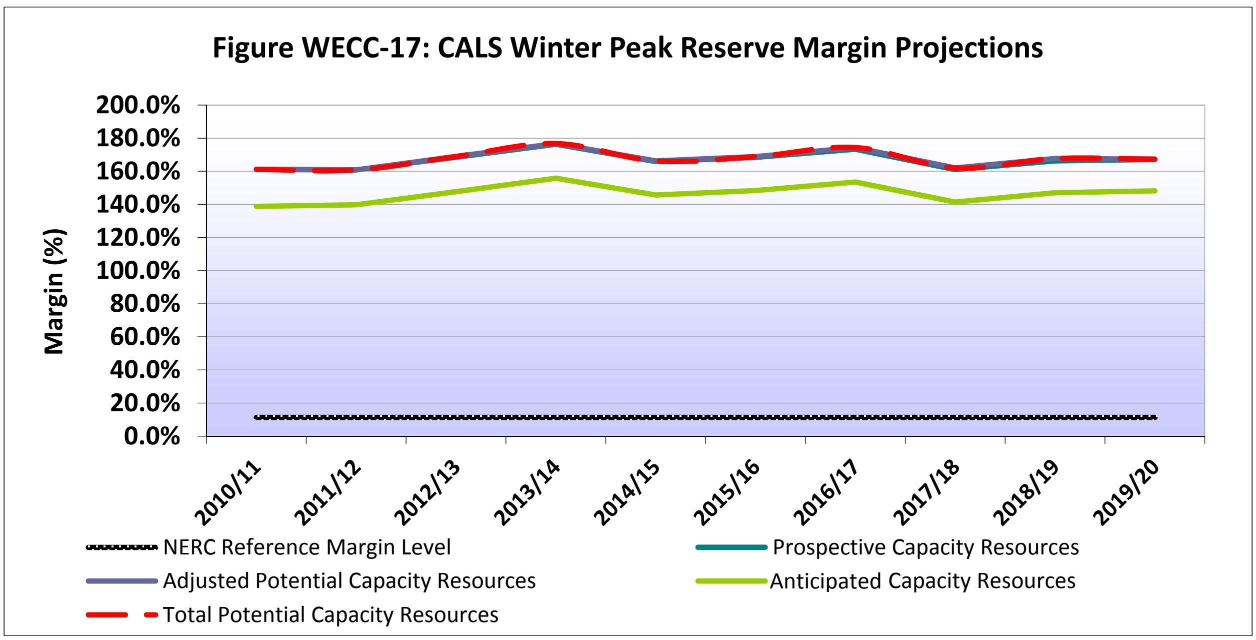
Table WECC-36: California-South			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	34,007	23,948	167,880
2009 Forecast, Coincident	33,704	23,446	167,681
2009 Actual, Coincident	33,917	22,912	161,508
Growth, Coincident %	-0.3%	-4.3%	-3.8%
Deviation from Forecast	0.6%	-2.3%	-3.7%
2010 Projected, Coincident	33,280	22,602	162,795
Growth, Coincident %	-1.9%	-1.4%	0.8%
2019 Projected, Coincident	37,133	25,126	181,271
2010 – 2019 Growth %	1.2%	1.2%	1.2%

Summer and winter peak demands for the California-South subregion increased by -0.3 percent and -4.3 percent respectively, from 2008 to 2009 while annual energy use increased by -3.8 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by 0.6 percent, -2.3 percent, and -3.7 percent, respectively.

Resource Adequacy Assessment

The California-South subregion target reserve margins are 14.8 percent for the summer and 11.4 percent for the winter. The projected reserve margins do not fall below the target reserve margins during the assessment period.





Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the California-South subregion has 1,540 MW, which is derated to 408 MW during the summer peak period.

Table WECC-37: California-South Existing and Potential Resources (through July 31, 2019)					
	Existing - Certain* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**35,485**	**28,095**	**0**	**296**	**28,391**
Conventional	31,077	7,958	0	296	8,254
Hydro	2,086	347	0	0	347
Wind	1,540	9,860	0	0	9,860
Biomass	352	49	0	0	49
Solar	430	9,881	0	0	9,881

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-38: California-South Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual (MW)	Total New Resources to 2019
Total Projected	28,743		17,398	0	296	17,694
Conventional Projected	26,137		7,958	0	296	8,254
Hydro Projected	1,596		220	0	0	220
Wind Projected	408		8	0	0	8
Biomass Projected	172		49	0	0	49
Solar Projected	430		9,163	0	0	9,163
Derates or Maintenance		6,742	10,697	0	0	10,697
Hydro Derate		490	127	0	0	127
Wind Derate		1,132	9,852	0	0	9,852
Biomass Derate		180	0	0	0	0
Solar Derate		0	718	0	0	718
Scheduled Outages		4,940	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

TRANSMISSION ASSESSMENT

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-39: California-South Transmission Line Circuit Miles					
Category	AC Voltage (kV)				
	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	2,709	5,679	101	2,499	10,988
Under Construction as of 1/1/2010	0	133	0	91	224
Planned - Completed within first five years	0	77	0	333	410
Conceptual - Completed within first five years	0	220	0	272	492
Planned - Completed within second five years	0	0	0	0	0
Conceptual - Completed within second five years	0	15	0	340	355
Total Under Construction and Planned Additions	0	210	0	424	634
Total Circuit Miles*	2,709	6,124	101	3,535	12,469

**May include projects that are duplicative in nature*

WECC – MEXICO (MEXW) SUBREGION

PEAK DEMAND AND ENERGY

The WECC-Mexico subregion encompasses the northern portion of Baja California, Mexico. For the period from 2010 to 2019, summer and winter Total Internal Demands are projected to grow at annual compound rates of 4.3 percent and 2.4 percent, respectively, while annual energy use is projected to grow at an annual compound rate of 4.4 percent.

Table WECC-31:WECC-Mexico			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Energy Use (GWh)
2008 Actual, Coincident	2,045	1,406	11,063
2009 Forecast, Coincident	2,115	1,480	10,687
2009 Actual, Coincident	2,077	1,397	10,743
Growth, Coincident %	1.6%	-0.6%	-2.9%
Deviation from Forecast	-1.8%	-5.6%	0.5%
2010 Projected, Coincident	2,140	1,472	11,355
Growth, Coincident %	3.0%	5.4%	5.7%
2019 Projected, Coincident	3,125	1,817	16,717
2010 – 2019 Growth %	4.3%	2.4%	4.4%

Summer and winter peak demands for the WECC-Mexico subregion increased by 1.6 percent and -0.6 percent respectively, from 2008 to 2009 while annual energy use increased by -2.9 percent. The 2009 actual summer and winter peak demands and energy use deviated from the forecast amounts by -1.8 percent, -5.6 percent, and 0.5 percent, respectively.

RESOURCE ADEQUACY ASSESSMENT

The WECC-Mexico subregion target reserve margins are 14.8 percent for the summer and 11.4 percent for the winter. The projected reserve margins – depicted on the following graphics – do not fall below the target reserve margins during the assessment period.

Figure WECC-18: Summer Peak Reserve Margin Projections

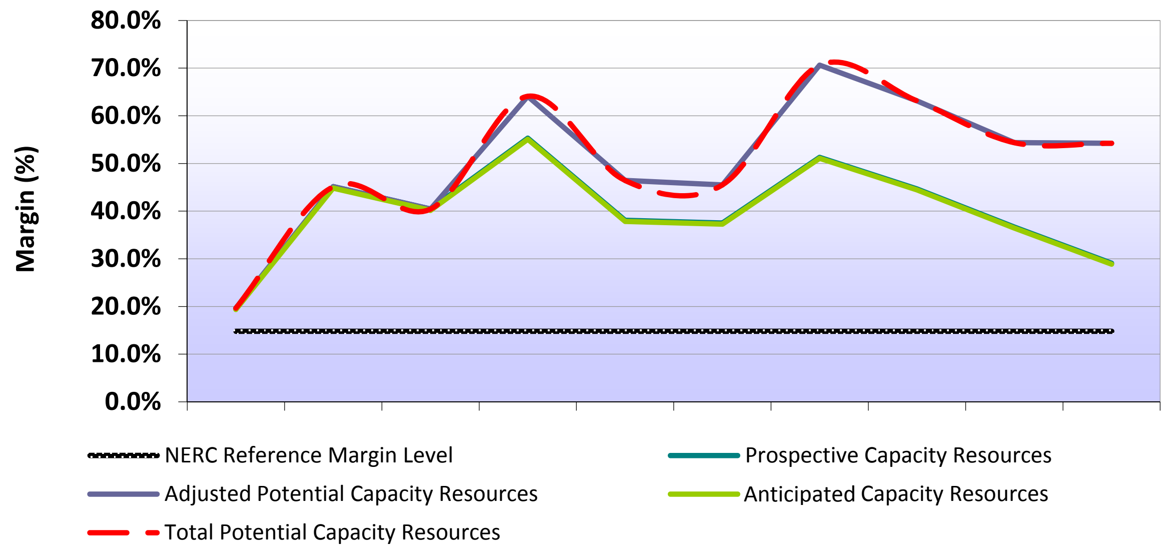
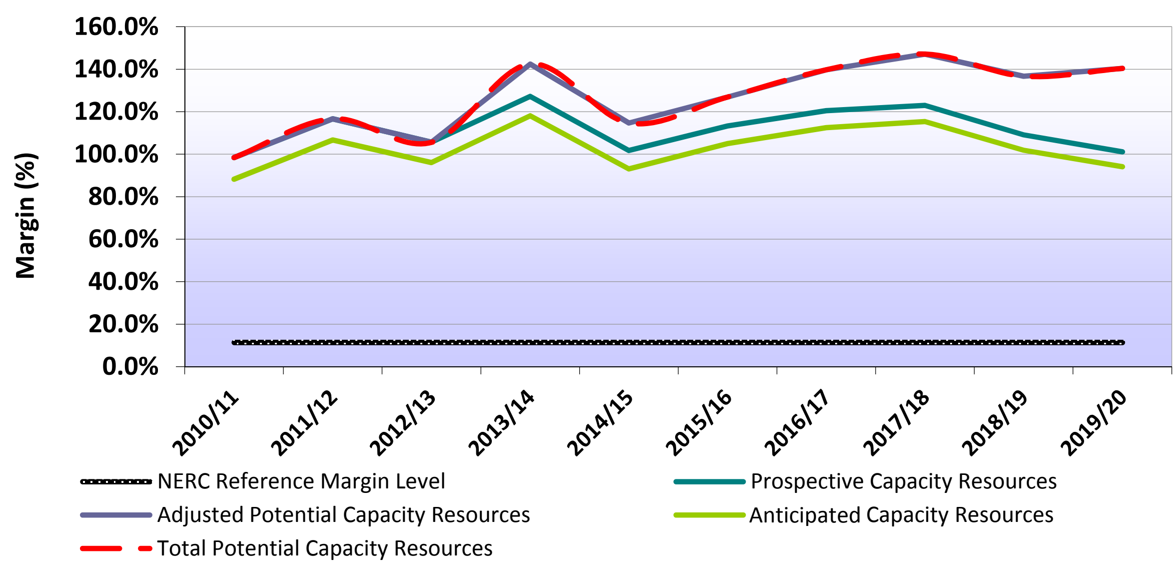


Figure WECC-19: Winter Peak Reserve Margin Projections



Of the existing wind resources within WECC, (10,041 MW of nameplate and derated to 2,180 MW on-peak) the WECC-Mexico subregion has 7 MW, which is derated to 1 MW during the summer peak period.

Table WECC-41: WECC-Mexico Existing and Potential Resources (through July 31, 2019)					
	Existing-Certain* (MW)	Future-Planned (MW)	Potential Future-Other (MW)	Potential Conceptual (MW)	Total New Capability to 2019
Total Installed	**2,614**	**1,134**	**0**	**787**	**1,921**
Conventional	2,607	1,134	0	787	1,921
Hydro	0	0	0	0	0
Wind	7	0	0	0	0
Biomass	0	0	0	0	0
Solar	0	0	0	0	0

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

Table WECC-42: WECC-Mexico Existing and Adjusted Resources (through July 31, 2019)						
	Existing-Certain* (MW)	Existing-Other (MW)	Future-Planned (MW)	Adjusted Future-Other (MW)	Adjusted Conceptual** (MW)	Total New Resources to 2019
Total Projected	2,608		1,134	0	787	1,921
Conventional Projected	2,607		1,134	0	787	1,921
Hydro Projected	0		0	0	0	0
Wind Projected	1		0	0	0	0
Biomass Projected	0		0	0	0	0
Solar Projected	0		0	0	0	0
Derates or Maintenance		6	0	0	0	0
Hydro Derate		0	0	0	0	0
Wind Derate		6	0	0	0	0
Biomass Derate		0	0	0	0	0
Solar Derate		0	0	0	0	0
Scheduled Outages		0	0	0	N/A	0
Confidence Factor				0%	100%	

**The Existing-Certain resources in this table represent the July 2010 values projected at the time of peak. The Existing-Other resources represent the amounts of reduction from the nameplate or seasonal values to get the EC values.*

***The Adjusted values represent the July 2019 peak values of the Future-Other or Conceptual resources after confidence factors were applied.*

FUEL SUPPLY AND DELIVERY

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 terminal near Ensenada. Fuel availability for electric power generation is not expected to be an issue during the ten-year planning horizon.

TRANSMISSION ASSESSMENT

The following table presents the existing transmission mileage and the planned transmission additions mileage during the assessment period.

Table WECC-43: WECC-Mexico Transmission Line Circuit Miles

	AC Voltage (kV)				
Category	100-199	200-299	300-399	400-599	Total AC
Existing as of 12/31/2009	740	662	0	0	1,402
Under Construction as of 1/1/2010	0	0	0	0	0
Planned - Completed within first five years	0	129	0	0	129
Conceptual - Completed within first five years	0	0	0	0	0
Planned - Completed within second five years	0	102	0	0	102
Conceptual - Completed within second five years	0	0	0	0	0
Total Under Construction and Planned Additions	0	231	0	0	231
Total Circuit Miles	740	893	0	0	1,633

**May include projects that are duplicative in nature*

OPERATIONAL ISSUES

No operational issues have been identified that would be expected to adversely impact electric power reliability in the Region during the ten-year planning horizon.

Cross-Regional ISO/RTOs

Midwest ISO

Executive Summary

The demand projections over the assessment time frame are affected by the additions to the Midwest ISO's membership. The projections in 2010 have changed since the 2009 reporting year due to the addition of three new transmission owners to the Midwest ISO membership. On September 1, 2009, MidAmerican Energy Company, Muscatine Power and Water, and the Municipal Electric utility of the city of Cedar Falls, Iowa successfully integrated into the Midwest ISO. In addition, Dairyland Power Cooperative joined as a transmission-owning member on June 1, 2010 and Big Rivers Electric Corporation plans to become a new member in September 2010. Although not reflected for in this assessment, there are also members departing from the Midwest ISO membership. First Energy plans to terminate its membership with the Midwest ISO in June 2011[236] whereas Duke Energy Ohio and Duke Energy Kentucky both plan to terminate membership in 2012. For consistency with other reporting entities, the effects of member departures are not reflected in this assessment. Due to the membership additions, the Midwest ISO's Total Internal Demand and the Net Internal Demand for the 10th year peak demand projection have increased since last year with a forecast of 119,110 MW and 115,769 MW, respectively.

Despite the additions to the Midwest ISO's membership, the 2010 average Existing-Certain resources over this assessment's ten-year period reflects only an increase of 70 MW compared to the prior 2009 reporting year. This is primarily due to the 2009 assessment not accounting for retirements or suspensions. In contrast, this year's assessment reduces the Existing-Certain capacity by retirements and suspensions. A contributing factor to the Existing-Certain capacity are reconstructed generators. The Taum Sauk pumped storage plant, which encountered a catastrophic failure on December 14, 2005, has undergone reconstruction replacing the upper reservoir dam. The construction is expected to be completed and the two generators are each capable of producing approximately 225 MW.

The Reserve Margins projected through the assessment timeframe vary with the additions to the membership. In order to maintain a reliability level based on LOLE requirements, the Midwest ISO has established a system Planning Reserve Margin of 15.4 percent for both the 2009 and 2010 planning years.[237] The average annual reserve margin over this assessment's ten-year period is 18.4 percent based on Existing-Certain and Net Firm Transaction resources. The average annual reserve margin over this assessment's ten-year period is 18.4 percent for Deliverable Resources, 29.7 percent for Prospective resources, and 65.9 percent for Potential resources. All the projected average annual reserve margins above exceed the 15.4 percent system Planning Reserve Margin requirement mentioned. There are no significant findings of a subregion's assessment in demand, capacity, and reserve margin projections. In addition, there are currently no reliability concerns identified in the Regional Assessment.

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[236] http://www.firstenergycorp.com/NewsReleases/2009-07-31%20RTO.pdf

[237] http://www.midwestmarket.org/publish/Document/4dfde8_124a04ca493_-7f5f0a48324a

The Morgan-Highway 22 transmission project, spanning 28 miles of 345 kV line, was placed in-service in October 2009 and has alleviated common constraints in the northern Wisconsin area. The Paddock-Rockdale transmission project, also in Wisconsin, added 35 miles of new 345 kV transmission additions. New 345 kV transmission lines are expected to be in service within the Midwest ISO with transmission lines spanning 54.6 miles in the American Transmission Co. (ATC LLC) area. There are currently no transmission reliability concerns identified in the coordinated seasonal assessment.

With respect to Operations, there are no important challenges with facing the operation of the bulk power systems within the Midwest ISO footprint to report at this time.

The Midwest ISO publishes an annual Long-Term Assessment Reliability Report that covers the assessment timeframe. [238]

INTRODUCTION

The demand and capacity projections over the assessment time frame are significantly affected by the additions to the Midwest ISO's membership.

DEMAND

The 2009 assessment resulted in a compound annual growth rate of 1.0 percent over the 2009-2018 timeframe and the 2010 projections resulted in a similar 1.1 percent compound annual growth rate over the 2010–2019 timeframe. The slight increase in this growth rate is due to the new member additions. The demands as reported by Network Customers are weather normalized, or 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 higher and a 50 percent chance the actual load will be lower than the forecast. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions.

An unrestricted non-coincident peak demand is created on a Regional basis by summing the non-coincident monthly forecasts for the individual Load Serving Entities (LSE) in the larger Regional area of interest. Using historic market data, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority and comparing them against the system peak. By taking the product of the diversity factor and the unrestricted non-coincident peak demand, the Midwest ISO is able to estimate a Total Internal Demand. The Midwest ISO does not currently track Energy Efficiency programs; however, they may be reflected in individual LSE load forecasts. The Midwest ISO currently separates Demand Resources into two separate categories, Interruptible Load and Direct Controlled Load Management (DCLM). Interruptible load of 2,874 MW projected 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. DCLM of 467 MW projected 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. DCLM is typically used for "peak

[238] http://www.midwestmarket.org/page/Regulatory+and+Economic+Studies

shaving." The Midwest ISO relies on Network Customers to provide weather normalized forecasts that account for the potential variability in projected demand due to weather, economic, or other key factors.

GENERATION

The average annual capacity over this assessment's ten-year timeframe is 122,525 MW for Existing-Certain capacity, 18,769 MW for Existing-Other capacity, and 1,518 MW for Future capacity resources (Planned and Other). The average annual capacity over this assessment's ten-year timeframe is 699 MW for Existing-Inoperable capacity, there are no projected Future-Planned capacity resources, and 1,518 MW for Future-Other capacity resources. Due to the intermittent nature of wind, it is difficult to predict the wind capacity available on peak. However, the Midwest ISO determined maximum wind capacity credits using an Equivalent Load Carrying Capacity (ELCC), a metric commonly used by the National Renewable Energy Laboratory (NREL). The Midwest ISO used the ELCC for wind generation and Loss of Load Expectation analyses for the Summer seasonal assessment. Wind shows an annual Existing-Certain capacity of 197 MW over this assessment's ten-year timeframe, which uses an eight percent capacity credit. The annual Existing-Other capacity for wind is 7,447 MW over this assessment's ten-year timeframe. Biomass shows an annual Existing-Certain capacity of 171 MW over this assessment's ten-year timeframe. The average annual Conceptual capacity resources is 32,276 MW over this assessment's ten-year timeframe with an average annual variable Capacity for Wind of 28,229 MW and Biomass of 166 MW.

The Midwest ISO uses Existing-Certain and Net Firm Transaction resources for reliability analyses and Reserve Margin calculations. A historical study establishing confidence factors based on fuel type was applied to the Midwest ISO Generation Interconnection Queue. Based on these analyses, the Midwest ISO used an overall confidence factor of 16 percent for Adjusted Conceptual Resources and 82 percent for Adjusted Future resources.

CAPACITY TRANSACTIONS ON PEAK

The Midwest ISO only reports power imports (not exports) to the Midwest ISO market or reported interchange transactions into the Midwest ISO market. The forecast reflects 5,549 MW of power imports from year-to-year. All these imports are firm and fully backed by firm transmission and firm generation. No imports assumptions are based on partial path reservations.

TRANSMISSION

New 345 kV transmission lines are Under Construction and are expected to be in service within the Midwest ISO. Specifically, transmission lines spanning 54.6 miles will be added to the American Transmission Co. (ATC LLC) area. Regional Generation Outlet Study (RGOS) is evaluating a number of other transmission expansions, some of which are expected to be in-service within the next ten years. Details on this study and transmission projects under evaluation can be found on the Midwest ISO website.[239] There are no potential reliability impacts in not meeting target in-service dates of transmission identified. The Midwest ISO does not have any transmission constraints that could

[239] http://www.midwestmarket.org/page/Renewable%20Energy%20Study

significantly impact reliability. A list of all approved transmission including those approved in MTEP09 can be found on the Midwest ISO website.[240]

OPERATIONAL ISSUES

There are no foreseeable existing or potential systemic outages that may impact reliability during the next ten years. Amongst other measures, the Midwest ISO uses transmission loading relief, normal binding procedures, and reserve deployment as temporary operating measures to maintain reliability. If peak demands are higher than expected, the Midwest ISO can 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. The Midwest ISO 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. The Midwest ISO plans on using variable dispatchable technology[241] 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.

RELIABILITY ASSESSMENT ANALYSIS

The Midwest ISO's system Planning Reserve Margin for the 2010/11 planning year is 15.4 percent, unchanged from the 2009/10 Planning Year. The average annual Reserve Margin based on Existing-Certain and Net Firm Transactions is 20.2 percent over this assessment's ten-year timeframe which is greater than 15.4 percent and the 2010 NERC Reference Margin level of 15.0 percent. The overall system Planning Reserve Margin was unchanged from 2009/10 assuming that LSEs maintain capacity resources for the following: 1) Resource Adequacy Requirements, 2) LSE requirements to reliably serve load, and 3) to meet LOLE expectations. The Midwest ISO has published a separate report further explaining the Planning Reserve Margin Findings.[242] The Midwest ISO conducted the 2010-2011 Loss of Load Study and introduced an unforced capacity reserve margin of 4.50 percent through using GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. This study can be found on the Midwest ISO website.[243]

The Existing-Certain and Net Firm Transactions, which reflects an average annual value of 132,165 MW over this assessment's ten-year timeframe, is relied on to calculate the average annual reserve margin of 20.2 percent mentioned above. The Midwest ISO only reports power imports to the Midwest ISO market or reported interchange transactions into the Midwest ISO. The forecast reflects 5,549 MW of typical power imports (reported by the Midwest ISO as externals) from year-to-year to meet the target reserve margin levels. All these imports are firm and fully backed by firm transmission and firm

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[240] http://www.midwestmarket.org/publish/Folder/193f68_1118e81057f_-7f8e0a48324a?

[241] http://www.narucmeetings.org/Presentations/midwestisonarucfebruary142010.pdf

[242] http://www.midwestmarket.org/publish/Document/4dfde8_124a04ca493_-7f5f0a48324a

[243] http://www.midwestiso.org/publish/Document/13b9ea_1265d1d192a_-7b910a48324a/2010%20LOLE%20Study%20Report.pdf?action=download&_property=Attachment

generation. The forecasts project load monthly from 2010 to 2012 and beyond 2012, the forecasts are reflected on a seasonal basis. Reserve Margins are calculated consistently and Reserve Margin requirements do not differ over the assessment period.

For inclusion in seasonal assessments, the Midwest ISO uses Energy Information Administration fuel forecasts to identify any system wide fuel shortages and there were none projected for the 2010 summer period. In addition to the seasonal assessments, the Midwest ISO's Independent Market Monitor submits a monthly report to the Midwest ISO's Board of Directors which covers fuel availability and security issues. During the operating horizon, the Midwest ISO 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. The Midwest ISO does not analyze energy-only resources in the resource adequacy assessment, however, transmission-limited resources are considered.

There are large amounts of wind generation that must be integrated while meeting state Renewable Portfolio Standards (RPS) within the Midwest ISO footprint. The Midwest ISO initiated the Regional Outlet Study (RGOS) to develop a set of Regionally coordinated transmission projects that meet both individual state RPS standards and LSE renewable goals with the minimum costs directed to the consumer. Due to the intermittent nature of wind, there is difficulty in predicting the wind capacity available on peak. However, the Midwest ISO determines a maximum wind capacity credit using an Equivalent Load Carrying Capacity, a metric commonly used by the National Renewable Energy Laboratory (NREL). The wind capacity credit is used for wind generation and Loss of Load Expectation analyses. The RGOS is evaluating a number of other robust transmission expansion plans, some of which are expected to be in-service within the next ten years. Details on this study and transmission projects under evaluation can be found on the Midwest ISO website.[244].

Demand Response reduces the Total Internal Demand to arrive at the Net Internal Demand. The Midwest ISO currently separates Demand Resources into two separate categories, Direct Controlled Load Management and Interruptible Load. If peak demands are higher than expected, the Midwest ISO can call the Local Balancing Authorities to deploy Demand Response, however, the Local Balancing Authorities also have the option to independently deploy Demand Response that they may have. There are no other expected changes to the planning approaches.

There are currently no foreseeable unit retirements which will have significant impact on reliability. There are no reported plans regarding Under Voltage Load-Shedding (UVLS) schemes or special protection systems/remedial action schemes that will be installed in lieu of planned bulk power transmission facilities in the Midwest ISO. The Midwest ISO does not have a planning process specifically for catastrophic events since there are operating procedures to mitigate issues during such an event.

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[244] http://www.midwestmarket.org/page/Renewable%20Energy%20Study

The Midwest ISO conducts an annual Long-Term Assessment to identify any reliability issues and addresses them. The Assessment includes an analysis over a ten-year time frame evaluating demand, capacity, and reserve margins. In addition, the Assessment includes a risk assessment section, which analyzes case studies while ensuring that LOLE requirements are met throughout the assessment timeframe. The Midwest ISO will report any dynamic and static reactive power-limited areas on the bulk power system and the plans to mitigate them.[245] The Midwest ISO historically provides a Voltage Stability Analysis in the annual MTEP report. In 2009, the study did not find low voltage areas or voltage collapse points for critical contingencies in transfer scenarios that are close to the base load levels modeled in the MTEP 09 2014 Summer Peak model.[246]

There are no Smart Programs to mention, which have been fully implemented in the past year that may significantly influence reliability. However, the Midwest ISO became the first Regional transmission organization (RTO) to enter into an agreement with the Unites States Department of Energy to implement more than 150 phasor measurement units (PMUs), also known as synchrophasors. PMUs are an integral element in modernizing the grid. The high-tech devices will monitor the state of the electrical grid 30 times per second, instead of the current once every four seconds, increasing the efficiency and reliability of power delivery. The data is then GPS time-stamped. This allows the data to be 'synchronized' which enables enhanced grid visualization, operational awareness, stability monitoring, state estimation, and after-the-fact analysis.

There are no reported project slow-downs, deferrals, or cancellations which may impact reliability in the Midwest ISO footprint.

Other Region-specific issues

There are no other actions taken to minimize any other anticipated reliability concerns during the next ten years.

Region Description

The Midwest ISO membership consists of 35 Transmission Owners with $17.4 billion in transmission assets under Midwest ISO's functional control and 100 Non-transmission owners. The Midwest ISO has four Balancing Authorities in the Region including the Midwest ISO Balancing authority and experiences its annual peak during the summer seasons. The Midwest ISO's scope of operations covers 56,300 miles of transmission over 13 states and one Canadian province. The Midwest ISO's Energy and Operating Reserves market includes 347 market participants who serve over 40 million people[247].

[245] http://www.midwestmarket.org/publish/Document/2c2ca5_12511ba6cdc_-7fab0a48324a

[246] http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5d0a48324a?

[247] http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-7ba50a48324a/FactSheet_0510f%20(2).pdf

PJM ISO

EXECUTIVE SUMMARY

An anticipated economic rebound causes load growth to resume in 2010, though it is anticipated that summer peak loads will not exceed the 2008 level until 2011. Summer peak load growth for the PJM RTO is projected to average 1.7 percent per year over the next 10 years. The PJM RTO summer peak is forecasted to be 161,047 MW in 2020, a 10-year increase of 25,297 MW. PJM has 165,747 MW of Existing-Certain capacity for the June 1, 2010 through May 31, 2011 planning period. This is an increase of 254 MW of Existing-Certain resources over last year's Existing-Certain. Future-Planned resources increase the PJM installed capacity by 29,550 MW over the assessment period. Existing-on-Peak-Wind is presently 516 MW (3,340 MW nameplate) and is expected to increase to 2,262 MW (20,740 MW nameplate) over the assessment period. Existing on-peak solar is presently 0 MW and is expected to increase to 14.7 MW over the assessment period. The PJM Reserve Margin requirement ranges from 15.5 percent in 2010-2011 to 15.3 percent in 2020. PJM is expected to meet its Reserve Margin requirements through the entire ten year period and has over 40,000 MW of Planned and Conceptual generation in its interconnection queues. Assuming just Existing-Certain and Planned resources are in service, PJM will just meet its Reserve Margin requirements in 2015. Only resources committed to the PJM Reliability Pricing Model (RPM) market and planned capacity additions were counted towards meeting the PJM reserve margin requirement.

There are no significant transmission additions since last year's assessment and no significant transmission constraints are anticipated. Several significant transmission enhancements are expected to go in-service during the assessment period including the addition of the Jacks Mountain 500 kV substation, the TrAIL Project (500 kV line and substations), Susquehanna-Roseland 500 kV line, the PATH (765 kV line and substations) and the MAPP 500 kV line.

No near-term system operating issues are expected. Longer-term operating issues associated with transmission construction delays are possible. Available mitigating measures include redispatch of generation, operating procedures, and new special protection systems.

PJM is expected to meet its Reserve Margin requirements through the entire ten-year period and has over 40,000 MW of generation in its interconnection queues. Many states in PJM have Renewable Portfolio Standards and it's 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. Generator retirements are evaluated for reliability impacts as each retirement is proposed. If it is determined that a reliability impact exists, the unit will not be allowed to retire until the reliability impacts are addressed. PJM has developed internal real-time systems to track and analyze gas pipeline issues. PJM can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of the PJM EMS contingency analysis package. Depending on the advance notice, PJM can adjust operating plans or implement emergency procedures consistent with PJM manuals. 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. The plan is issued annually.

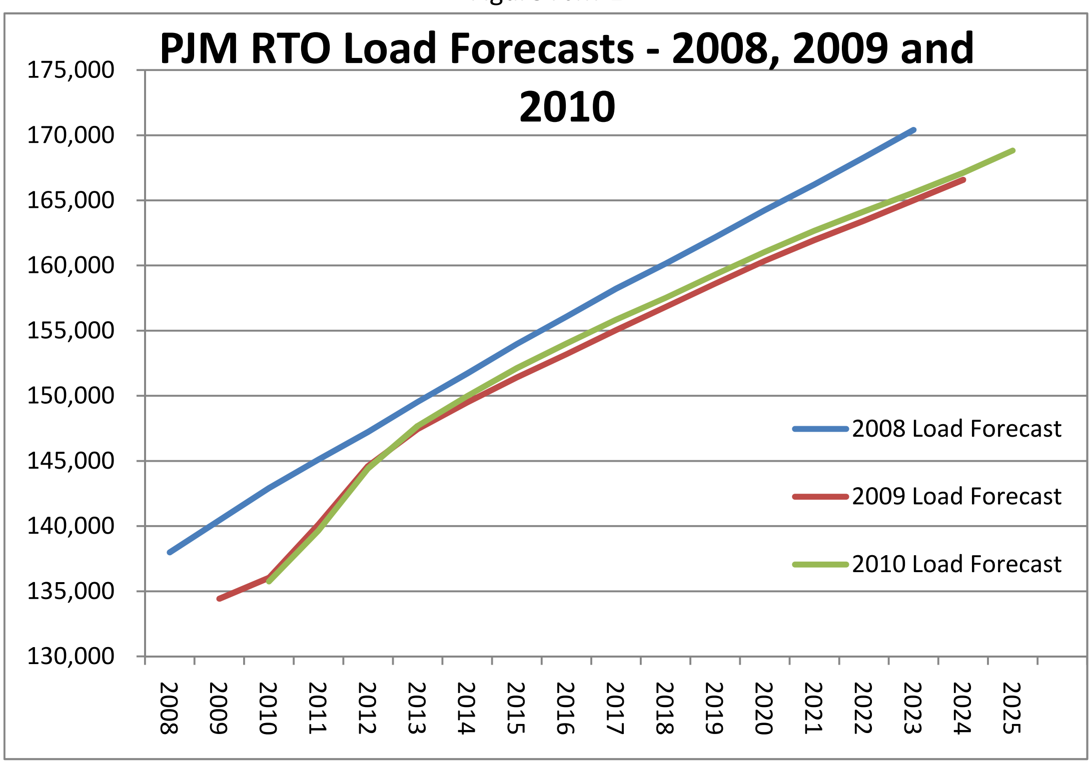
Introduction

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.

Demand

An anticipated economic rebound in 2010 will cause load growth to resume in 2010, though it is anticipated that summer peak loads will not exceed the 2008 level until 2011. Summer peak load growth for the PJM RTO is projected to average 1.7 percent per year over the next 10 years, and 1.5 percent over the next 15 years. The PJM RTO summer peak is forecasted to be 161,047 MW in 2020, a ten-year increase of 25,297 MW, and reaches 168,824 MW in 2025, a fifteen-year increase of 33,074 MW. Annualized ten-year growth rates for individual PJM transmission zones range from 1.0 percent to 2.5 percent. Compared to the 2009 long-term forecast of summer peak demand, the 2010 forecast of Total Internal Demand is very similar (Figure PJM-1) Significant differences in the forecast of Net Internal

Figure PJM-1



Demand from the 2009 PJM Load Report [248] result from a significant increase in expected Load Management and Energy Efficiency impacts.

The PJM load forecast does not use a specific weather assumption, but applied a Monte Carlo simulation using 35 years of historical weather from 1974 to 2008. The economic variable used in the PJM load forecast is Real Gross Metropolitan Product (GMP) for major metropolitan areas within the PJM RTO. The current forecast uses the November 2009 economic forecast release from Moody's Economy.com. The 2010 forecast uses economic growth assumptions, which closely parallel those from the 2009 forecast: an economic rebound will take hold and accelerate through 2012, then moderate through the remainder of the forecast horizon. For the PJM RTO, the assumption for economic growth for the ten-year forecast is for GMP to grow at a compound average growth rate of 2.4 percent for 2010 to 2020.

PJM forecasts the load of the entire RTO and the individual transmission zones on a coincident basis. As PJM is summer-peaking, the coincident summer peaks are used in resource adequacy evaluations.

Energy efficiency programs included in the 2010 load forecast are impacts approved for use in the PJM RPM. At time of the 2010 load forecast publication, nearly 550 MW of Energy Efficiency programs have been approved as RPM resources. Measurement and verification of Energy Efficiency programs are governed by rules specified in PJM Manual 18B[249]. 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 measurement and verification plans, providing post-installation measurement and verification reports, and undergoing a measurement and verification audit.

For the 2010/2011 delivery year PJM had contractually interruptible Demand-Side Management of 9,053 MW. Similar values are anticipated through the assessment period. No Demand-Side Management resources or Energy Efficiency is specifically used for meeting renewable portfolio standards.

The PJM load forecast process produces a weather distribution of peak-load forecasts by applying a Monte Carlo simulation using 35 years of historical weather from 1974 to 2008. 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 165,747 MW of Existing-Certain capacity for the June 1, 2010 through May 31, 2011 planning period. Future-Planned resources increase the capacity by 29,550 MW by the end of the assessment period. Wind-Nameplate resources amount to 3,340 MW presently and are expected to increase by 17,400 MW over the assessment period. Wind-Existing-on-Peak is presently 516 MW and is expected to

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[248] http://www.pjm.com/documents/~/media/documents/reports/2010-load-forecast-report.ashx

[249] http://www.pjm.com/~/media/documents/manuals/m18b.ashx

increase to 2,262 MW over the assessment period. Wind-Energy-Only-Nameplate is currently 278 MW. There are currently no solar Existing-Certain resources in PJM but 26 MW of Planned-Solar-Nameplate is expected to be added over the assessment period. Solar-on-Peak is expected to be 14.7 MW by the end of the assessment period. 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. 927 MW of biomass exists in PJM and 44 MW is planned.

PJM has a total of 13,316 MW of Conceptual capacity over the assessment period. Conceptual-Wind-Nameplate resources are expected to increase by 17,142 MW over the assessment period. Conceptual-Wind-on-Peak is expected to increase 2,228 MW over the assessment period. Conceptual-Solar-Nameplate of 596 MW is proposed. PJM has 254 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 (RTEP) to determine required transmission expansion if necessary. The calculation of Commercial Probability uses historically gathered information to assign probabilities to each of four stages: feasibility study complete, impact study complete, facility study complete and signed Interconnection Service Agreement. 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[250].

CAPACITY TRANSACTIONS ON PEAK

Existing-Firm imports total 3,229 MW for the PJM RTO. There are no Expected or Provisional transactions counted towards meeting the reserve margin requirements. All transactions are firm for both generation and transmission. No imports are based on partial path reservations.

Existing-Firm exports total 2,806 MW for the PJM RTO. There are no Expected or Provisional transactions. All transactions are firm for both generation and transmission. No imports are based on partial path reservations.

TRANSMISSION

As a Federal Energy Regulatory Commission approved Regional Transmission Organization, one of PJM's core functions encompasses Regional transmission planning. PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission upgrades and enhancements that are required to preserve the reliability of the transmission system. The PJM system is planned such that it can be operated to supply

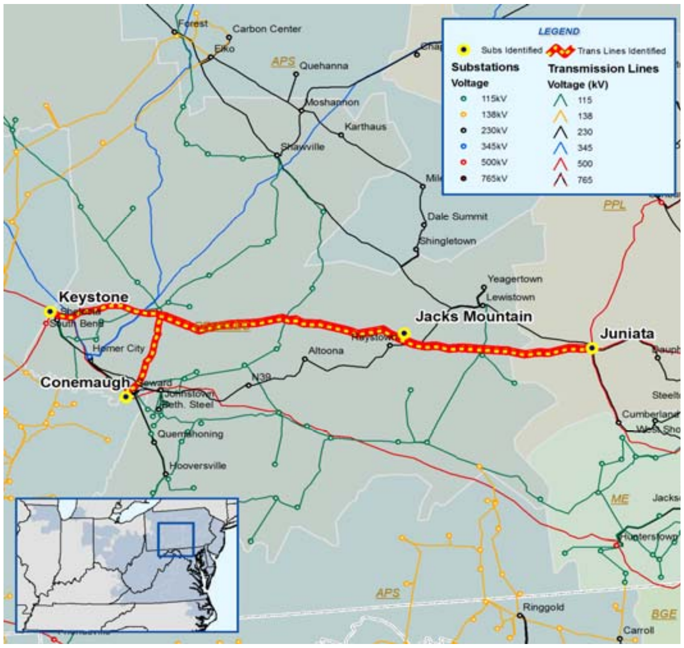
[250] http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx

projected customer demands and projected firm transmission service over a range of forecast system demands under contingency conditions that have a reasonable probability of occurrence. PJM reliability planning encompasses a comprehensive series of detailed analysis that ensures reliability and compliance under the most stringent of the applicable NERC, Regional Entity (RFC or SERC as applicable), PJM and local criteria. To accomplish this each year, a baseline assessment is completed for applicable facilities over the near term (one to five years) and longer term (six to fifteen years). Bulk electric system (BES) facilities are included in the RTEP baseline assessment process as required by NERC standards. Following are details on large transmission projects in PJM.

Jacks Mountain

The 2006 RTEP identified widespread voltage problems for the Eastern Mid-Atlantic Load Deliverability test. The approved solution to address these voltage violations is to build a new 500 kV substation at Jacks Mountain (formerly known as Airydale) in central Pennsylvania by tapping the existing Keystone to Juniata 500 kV line and the Conemaugh to Juniata 500 kV line. The station will have 1,000 MVAr of shunt capacitors to provide reactive support to the 500 kV system in the Mid-Atlantic area of PJM. Updated analyses done as part of the 2009 RTEP indicate that this project is not needed to be in-service until 2012.

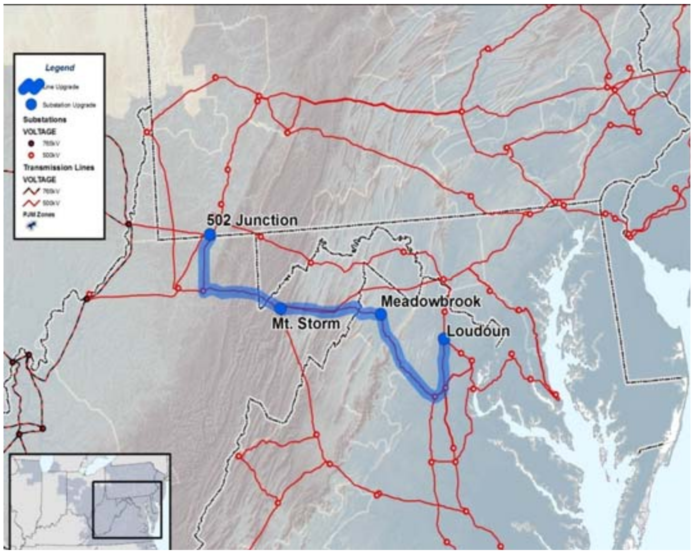
Figure PJM-2: Jack's Mountain Substation



TrAIL Project – 502 Junction to Loudoun 500 kV

The 2006 RTEP identified the need for a new 500 kV line across the Allegheny Mountain corridor to address thermal criteria violations on several 500 kV lines. Updated analyses done as part of the 2007 and 2008 RTEPs confirmed the need for the new line and validated the June 2011 required in-service date. Updated analyses done as part of the 2009 RTEP continue to show the need for the line to be in-service by June 2011.

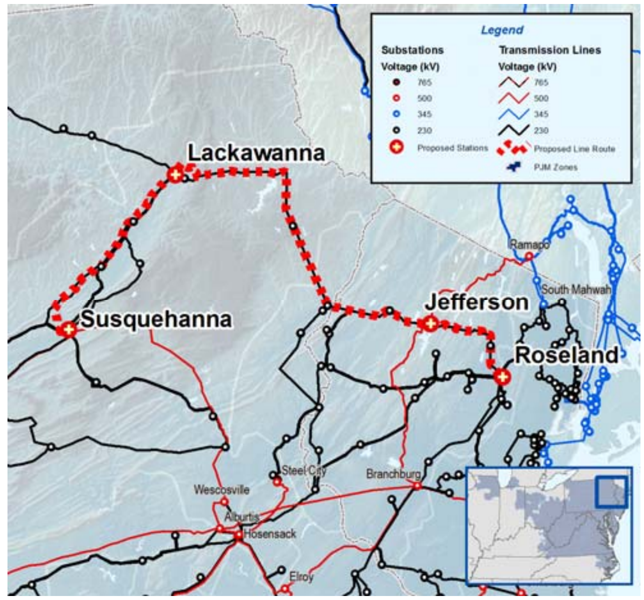
Figure PJM-3: TrAIL Project



Susquehanna – Roseland Project

The 2007 RTEP identified the need for the Susquehanna – Roseland project to resolve a number of criteria violations in the eastern Mid-Atlantic area of PJM. The project includes the construction of a new 500 kV line from the Susquehanna substation in northeastern Pennsylvania to Lackawanna where a new 500/230 kV substation will be built to reinforce the existing 230 kV system. From Lackawanna, the line will cross into New Jersey to a new 500 kV substation called Jefferson. The Jefferson substation will interconnect the new line to the existing Branchburg to Ramapo 500 kV line. From Jefferson substation, the line will continue east to the Roseland substation in northern New Jersey where it will interconnect to the underlying 230 kV system. The results of the 2009 RTEP analyses confirmed the need for the Susquehanna to Roseland project to be in service by 2012.

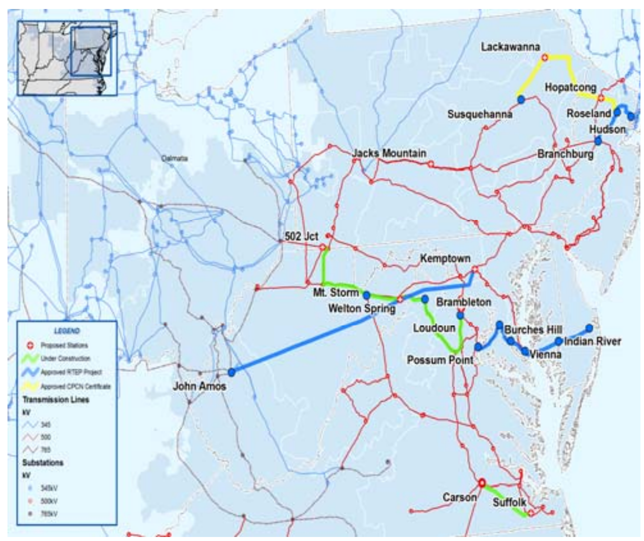
Figure PJM-4: Susquehanna – Roseland



PATH Project – Amos to Welton Spring to Kemptown 765 kV

The 2007 RTEP identified multiple criteria violations on 500 kV lines across Pennsylvania and across the Allegheny Mountains that were expected to occur as early as 2012. The approved solution to address these reliability criteria violations was to build a new EHV transmission line from Amos 765 kV in West Virginia to the new Welton Spring 765 kV substation also in West Virginia and finally to the new Kemptown 765 kV substation in Maryland. As part of the 2008 RTEP the required in-service date for the project was deferred to 2013. Based on the updated analyses conducted as part of the 2009 RTEP there were no criteria violations identified in 2013 however, beginning in 2014 widespread thermal and voltage violations were identified.

Figure PJM-5: PATH Project

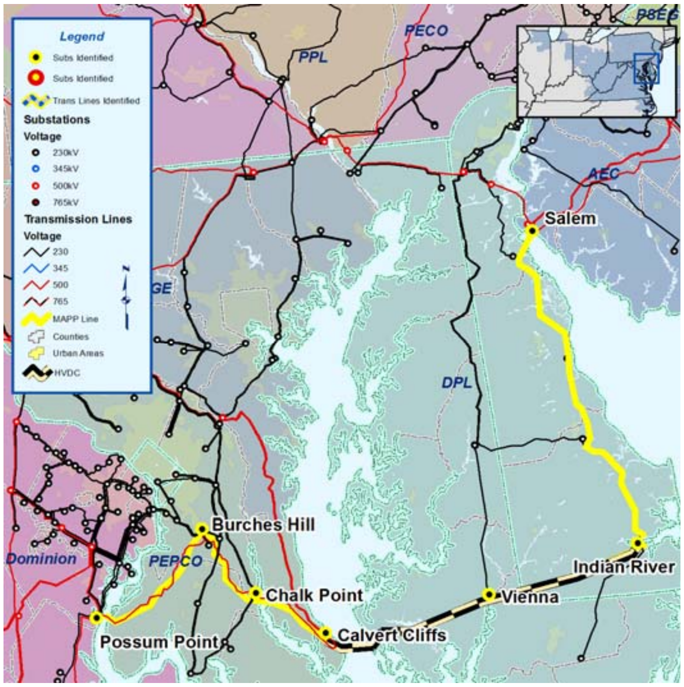


The 2009 RTEP analyses identified thirty one different contingencies that resulted in voltage collapse for the Mid-Atlantic load deliverability test in 2014. PJM staff completed extensive PV analysis to determine the point of collapse for the various contingencies. As a result of the updated analyses, the required in-service date for the PATH project has been deferred to 2014.

MAPP – Mid-Atlantic Power Pathway Project

The 2007 RTEP identified the need for the MAPP project to address significant thermal violations in the Southwestern Mid-Atlantic area of PJM as well as on the Delmarva Peninsula. Updated analyses completed as part of the 2008 RTEP confirmed the need for the project in 2013 to resolve significant reactive violations. In addition, the project resolved numerous thermal violations on 500 kV, 230 kV and 138 kV facilities.

Figure PJM-6: MAAP Project



The 2009 RTEP identified additional voltage collapse conditions. In addition to the reactive problems noted above, there were multiple thermal violations on 230 kV and 138 kV facilities in the Southwest Mid-Atlantic area of PJM and on the Delmarva Peninsula with the earliest violation occurring in 2014. Based on this analysis, the required in-service date for the MAPP project from Possum Point to Indian River has been deferred until 2014. In addition, based on the 2009 RTEP analysis the Indian River to Salem portion of the MAPP project is not required and is being removed from the RTEP.

Potential reliability impacts of not meeting target in-service dates for projects identified above are under constant review to identify alternate plans or mitigating operational actions that should be taken in the event of project delays. Available mitigating measures include re-dispatch of generation, operating procedures, and special protection systems. Potential project delays may result from delays in regulatory approval, construction delays, and lead times associated with the availability of equipment. There are no significant changes from last year's assessment and no significant transmission constraints are anticipated.

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 redispatch 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. If demand is higher than expected, PJM can implement emergency procedures identified in the PJM Emergency Procedures Manual (M13), Section 2: Capacity Conditions[251].

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 capacity (less than 500 MW) and only kick in after the units run for a period of time.

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 nor is 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.

Reliability Assessment Analysis

The PJM Reserve Margin requirement for the June 1, 2010 through May 31, 2011 and the June 1, 2011 through May 31, 2012 planning periods is 15.5 percent. For June 1, 2012 through May 31, 2013 the Reserve Margin Requirement is 15.4 percent and for June 1, 2013 through May 31, 2020 the Reserve Margin Requirement is 15.3 percent. PJM is expected to meet its Reserve Margin Requirements through the entire ten-year period and has over 40,000 MW of Future-Planned and Conceptual generation in its interconnection queues. Assuming just Existing-Certain and Future-Planned resources are in service, PJM will just meet its Reserve Margin requirements in 2015.

PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in ten years. 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

[251] http://www.pjm.com/~/media/documents/manuals/m13.ashx

Manual 20[252] .The latest resource adequacy study was completed in November, 2009[253]. This study examined the period 2009 to 2019.

PJM resources climb from 166,000 MW in 2010 to over 195,000 MW by the end of 2020. Only resources committed to the PJM RPM market and Future-Planned capacity additions were counted towards meeting the PJM reserve margin requirement. PJM does not rely on any external emergency assistance for planning purposes.

The PJM reserve requirement is calculated and required for up to three years into the future. PJM assumes the last calculated PJM Reserve Requirement to apply to all subsequent years. After our three-year planning window, a Commercial Probability [254]is applied to the generator interconnection queues to determine how much generation in aggregate should be applied to our adequacy in longer-term years.

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.

Transmission-limited and energy-only units are not considered in PJM reliability analysis. They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance.

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 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 plant's capacity factor. Variable resources are treated just like other resources but with the resource adequacy assumptions mentioned previously. We have a small penetration of variable resources at this time and may develop special 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

[252] http://www.pjm.com/documents/~/media/documents/manuals/m20.ashx

[253] http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-reserve-requirement-study.ashx

[254] http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx

their full value. Failure to provide such data will result in a significant financial penalty to the Demand Response provider.

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. Generator retirement information is available on the PJM website[255].

PJM does not have a UVLS program at the Transmission Operator level. PJM security analysis does not recognize such programs as part of its security analysis contingency definition.

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 developed internal real-time systems to track and analyze gas pipeline issues. PJM can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of the PJM EMS contingency analysis package. Depending on the advance notice, PJM can adjust operating plans or implement emergency procedures consistent with PJM manuals.

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.

In addition to the thermal limits, PJM operates the system 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 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.

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

[255] http://www.pjm.com/planning/generation-retirements.aspx

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 transfer limit is then created by backing off the IROL limit by a predetermined amount. This back off from the calculated limit adds a voltage stability margin for operating purposes. 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.

PJM companies are in the process of installing an additional 80 phasor measurement units adding to the twenty in place already. Under the new program, twelve PJM transmission owners will install phasor measurement units in substations in ten different states (Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia). The PMU's data will be concentrated at PJM for analysis and model validation purposes. 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.

OTHER REGION-SPECIFIC

There are no anticipated project slow-downs, deferrals or cancellations, which may affect reliability in PJM. No other reliability concerns are anticipated during the next ten years.

REGION DESCRIPTION

PJM has 604 members that operate within 168,500 square miles of service territory. 1,271 generators with diverse fuels serve a single summer peaking Balancing Authority. PJM is in two NERC Regional Entities (RFC and SERC). PJM companies serve 51 million people in 13 states and Washington DC (DE, IL, IN, KY, MD, MI, NC, NJ, OH, PA, TN, VA, WVA)

Appendix I: About this Report

Background

The *2010 Long-Term Reliability Assessment* represents NERC's independent judgment of the reliability of the BPS in North America for the coming ten years (Table Report 1).[256] The report specifically provides a high-level reliability assessment of the 2010 to 2019 seasonal resource adequacy and operating reliability, an overview of projected electricity demand growth, Regional highlights, and Regional self-assessments.

Table Report-1: NERC's Annual Assessments		
Assessment	**Outlook**	**Publish Target**
Summer	Upcoming season	May
Post-Summer	Previous season	November
Long-Term Assessment	10 year	October
Winter	Upcoming season	November
Post-Winter	Previous season	May

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.[257] 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.[258] 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 *2010 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 2010 and updated, as required, throughout the drafting process. Any

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[256] 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.

[257] 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."

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

other data sources consulted by NERC staff in the preparation of this document are identified in the report.

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

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

In the *2010 Long-Term Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[259]

- Supply and demand projections are based on industry forecasts submitted in May 2010. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting timeframe (May – August).
- Peak demand and Reserve Margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned; planned outages take place as scheduled.
- Demand reductions expected from dispatchable and controllable Demand Response programs will yield the forecast results, if they are called on.
- Other peak Demand-Side Management programs, such as Energy Efficiency and price-responsive Demand Response, are reflected in the forecasts of Net Internal Demand.

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

[259] 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).

of the reliability of the coming ten 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 ensures the Reliability Assessment Database operates with consistent data. It uses routines, often called "validation rules," that check for correctness, meaningfulness, and security of data that are added into the system.

Table Data Checking 1: NERC Data Quality Framework and Attributes

Data Quality Attribute	Responsible Entity	Data Check Performed
Accuracy *Ensure data are the correct values*	Industry	• Validation rules • Consistent with other external sources
Accessibility *Data items should be easily obtainable and in a usable format*	DCWG, NERC, and RE	• Data is submitted in the provided template
Comprehensiveness *All required data items are submitted*	DCWG, RE, and Stakeholders	• Check for null values • Compare to prior year's null values • Inquiries to the RE
Currentness *The data should be up-to-date*	RE and Stakeholders	• Consistent with other external sources
Consistency *The value of the data should be reliable and the same across different reporting entities*	DCWG, NERC	• DCWG leads in this effort • Assumptions are verified with the RE
Definition *Clear definitions should be provided so the current and future data users can understand the assumptions*	DCWG, NERC Staff	• The DCWG leads in this effort

Internal data checking and validation refers to the practice of validating and checking data through internal processes (*e.g.*, Historical Comparison, Range and Limits, Data Entry Completeness, Correct Summations) to maintain high quality data (See Table Data Checking 1). The rules are implemented through automated processes — data dictionary for data checking and logic for validation. Incorrect data can lead to data corruption or a loss of data integrity. Data validation verifies it is valid, sensible, and secure before it is processed for analysis. The program uses scripts, developed on a composite Microsoft Excel and Microsoft Access platform, to provide a semi-automated solution.

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. Regions were required to report individual generating unit-level supply data for *Long-Term Reliability Assessment*. 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

2010 to 2019 Long-Term Reliability Assessment Data Request

The data request letter provided to Regional Mangers on December 14, 2009 included the following instructions:

Regional Self Assessment — 2010 Long Term Reliability Assessment

Prepare a written assessment for your Region discussing any situations that could affect Prepare a written assessment for your Region discussing any anticipated situations that could affect reliability during the next ten years.

Each Region is requested to include the specific information covered in the sections below. If your Regional self-assessments are divided into subregions, the subregion assessments should address each of these sections and questions individually, with the overall Regional self-assessment providing a high-level overview. Consistent responses representing all subregions can be provided at the Regional level.

Please organize your self-assessment into the following template. Your self-assessment should respond to the following questions:

1. Demand

a) Compare last year's compound annual growth rate for 2009-2018 to this year's 2010–2019 10-year assessment timeframe for your 50/50 forecast, and present the key factors leading to any significant changes in the forecast.

b) Discuss weather and economic assumptions upon which the 2010–2019, 50/50 demand forecast is based.

c) What method is used to aggregate total internal peak demands of individual member's forecast loads for use in the forecast? Separately:

   i. Discuss if the Region/subregion peak information is coincident or non-coincident. Discuss which peak condition your Region/subregion(s) base their resource evaluations.

   ii. Specify and describe the current and projected Energy Efficiency programs. Review measurement and verification programs used for Energy Efficiency.

iii. Specify and describe the current and projected Demand Response programs that reduce peak demand — *i.e.* interruptible demand; direct control load management; critical peak pricing with control; load as a capacity resource, etc. Review measurement and verification programs used for Demand Response.

iv. Describe and identify Demand-Side Management resources (Energy Efficiency and Demand Response) which are used for meeting renewable portfolio standards.

d) Describe the Regional or subregional quantitative analyses evaluating the potential variability in projected demand due to weather, economic, or other key factors. Describe any changes that have been made to demand forecasting methods.

2. Generation

a) Identify the amount of Existing (Certain, Other and Inoperable) and Future (Planned and Other) capacity resources during the study period. Identify the portions (MW) that are:

i) Variable (*i.e.* wind, solar, etc.) capacity expected on peak and the maximum capacity from the variable plants. Discuss how expected on-peak capacity values are calculated in your Regions/subregions.

ii) Biomass (*e.g.*, wood, wood waste, municipal solid waste, landfill gas, ethanol, and other biomass).[260])

b) Identify the amount of Conceptual capacity resources expected to come on-line during the study period. Identify the portions (MW) that are:

i) Variable (*i.e.* wind, solar, etc.) capacity expected on peak and the maximum capacity from the variable plants. Discuss how capacity values are calculated in your Regions/subregions.

ii) Biomass (wood, wood waste, municipal solid waste, landfill gas, ethanol, and other biomass).[261]

c) In general, for Future and Conceptual capacity resources (quantify resource selections and allocations if possible):

i) Describe the process used to identify resources for reliability analysis/Reserve Margin calculations (*i.e.* forward capacity markets, obligation to serve activities, etc.).

ii) Discuss the process and assumptions used to apply the adjustment (or confidence factor) to Conceptual resources. (Conceptual resources, when adjusted by a confidence factor, are included in Adjusted Potential Resources)

iii) Further, describe the process and assumptions used to identify and categorize Conceptual resources (*e.g.*, total of all generation queue)

3. Capacity Transactions on Peak

a) Imports on Peak

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[260] Defined by EIA as: *"organic nonfossil material of biological origin constituting a renewable energy source."*

[261] Defined by EIA as: *"organic nonfossil material of biological origin constituting a renewable energy source."*

i) Identify and quantify imports from other Regions and those imports between your subregions that are part of their Reserve Margins. Categorize them as:

i. Firm — contract signed.
ii. Expected — no contract executed, but in negotiation, projected, or other.
iii. Provisional — transactions under study, but negotiations have not begun.

ii) What portion of the imports is backed by firm contracts for both generation (contract tied to specific generator) and transmission? Clarify if import assumptions are based on partial path reservations.

b) Exports on Peak

i) Identify and quantify exports to other Regions and those exports between your sub-Regions that are part of their Reserve Margins. Categorize them as:

i. Firm — contract signed.
ii. Expected — no contract executed, but in negotiation, projected, or other.
iii. Provisional — transactions under study, but negotiations have not begun.

ii) What portion of the exports is backed by firm contracts for both generation (contract tied to specific generator) and transmission? Clarify if export assumptions are based on partial path reservations.

4. Transmission

a) Describe any bulk power system transmission categorized as Under Construction, Planned or Conceptual (see data instruction sheets) anticipated in-service during the ten-year study period.

b) Are there any potential reliability impacts in not meeting target in-service dates of transmission identified in *4a*? For each potential reliability impact identified, discuss the following:

i. Describe how these potential reliability impacts are being addressed?

ii. Describe the cause of the delays.

b) Does the Region/subregion have any transmission constraints that could significantly impact reliability and what are the plans to address these constraints?

c) Provide a listing of any other significant substation equipment (*i.e.* SVC, FACTS controllers, HVdc, etc.)

5. Operational Issues (Known or Emerging)

a) Are there any existing or potential systemic outages that may impact reliability during the next ten years? Discuss the temporary operating measures which can be used to maintain reliability.

b) Discuss operational measures available if peak demands are higher than expected.

c) Are there either environmental or regulatory restrictions that could potentially impact reliability? If so, please explain, including the projected magnitude (in MW) of the restriction.

d) Describe any anticipated operational changes resulting from integration of variable resources (*i.e.* wind, solar, etc.)?

e) Are there operational changes or concerns resulting from distributed resource integration (*i.e.* significant amounts of generation connected to the distribution system, etc.)?

f) Do you anticipate any reliability concerns resulting from high-levels of Demand Response resources? If so, what operating measures are used to mitigate this?

6. Reliability Assessment Analysis

Describe the assessment process used by the Region and subregions. ***(Cite reports documenting studies in footnotes or reference).***

a) Identify the projected Reserve Margins and compare them to the Regional, subregional, state, or provincial requirements.

- i) What assumptions were used to establish the Regional/subregional Reserve Margin criteria, target margin level or resource adequacy levels (*i.e.* Loss-Of-Load Expectation, Expected Unserved Energy, etc.)?
- ii) Describe the latest resource adequacy studies (*i.e.* Loss-of-Load Expectation, Expected Unserved Energy, etc.).
- iii) What is the amount of resources internal and external to the Region or subregion that are relied on to meet the target margin level, or forecast load for the assessment period?[262]
- iv) Describe any reliance of the Region or subregions on emergency imports, reserve sharing or outside assistance/external resources (clarify whether it is external to the subregion or the Region), where these resources are expected to come from and coordination with other Regions which may also require these same resources.
- v) Does the Region/subregion treat short-term (*i.e.* 1-5 years) and long term (*i.e.* 6-10) Reserve Margins requirements differently? If so, describe.
- vi) Discuss resource adequacy if fuel interruptions or other conditions such as extended drought or forced outages are experienced.
- vii) Describe how energy-only and transmission-limited resources are considered in your resource adequacy assessment.
- viii) For variable renewable resources, discuss/describe
  - (i) Renewable Portfolio Standards (RPS) or other mandates that impact your resource adequacy process.
  - (ii) How variable resources are considered (*i.e.* wind, solar, etc.) in your resource adequacy assessment.
  - (iii) Planning approaches/changes developed to ensure reliable integration and operation of variable resources.

[262] Each Region/subregion may have their own specific margin level (or method) based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Margin Level. If not, NERC will assign a 15 percent Reference Margin Level for predominately thermal systems and 10 percent for predominately hydro systems

ix) Discuss how Demand Response is considered in the resource adequacy assessment. Discuss the planning approaches currently used to ensure expected Demand Response resources perform as expected. Further, discuss any expected changes to the planning approaches.

b) Identify unit retirements which have significant impact on reliability. What measures have you taken to mitigate the reliability concern?

c) Do you expect to install additional Under Voltage Load-Shedding (UVLS) schemes in your Region/subregion? How much load (MW) is targeted by Under Voltage Load-Shedding (UVLS) to protect against bulk power system cascading events and how does this influence your reliability assessment?

d) Describe whether any special protection systems/remedial action schemes will be installed in lieu of planned bulk power transmission facilities, and identify whether it will be a permanent or temporary solution.

e) Describe the Region/subregion planning process for catastrophic events: for example, the loss of a fleet of generators due to earthquakes, hurricanes, major pipeline or fuel disruption, geomagnetic induced currents, or loss of a major import path.

f) Describe the planning studies performed by your Region's Transmission Planners, what reliability issues were identified and what are the plans to address them. In addition:

   i. Describe any dynamic and static reactive power-limited areas on the bulk power system in your Region/subregion and plans to mitigate them.

   ii. Do you have criteria for voltage stability margin in your Region/subregion? If yes, state the criteria and explain how it is being applied to meet the peak summer conditions.[263]

g) What new technologies, systems, and/or tools does the Region expect to deploy to improve bulk power system reliability (*e.g.*, "smart grids," FACTS.)?

h) Describe significant smart grid programs (current and future) which:

   i. may enhance reliability.

   ii. have potential reliability issues.

i) Are there any project slow-downs, deferrals, cancellations, etc which may impact reliability in your Region/sub-Region?

7. Other Region-specific issues that were not mentioned above?

Discuss what the Region is doing to minimize any other anticipated reliability concerns during the next ten years.

8. Region Description

List the number of members, Balancing Authorities, and other organizations (associate members, for instance) in the Region. State the season in which the Region typically experiences its peak demand, the number of square miles in the Region, the states that comprise the Region and the approximate total population served.

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[263] ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/Survey-of-the-Voltage-Collapse-Phenomenon-Optimized.pdf

REPORT CONTENT RESPONSIBILITY

In close collaboration with NERC staff, the RAS oversees the preparation of the seasonal and Long-Term Reliability Assessments. The RAS reports to the PC and its members prepare the Regional data and narratives, conduct peer reviews, develop Emerging Issues, and contribute to the report writing and review process. The following NERC industry groups have also collaborated efforts to produce NERC's *2009 Long-Term Reliability Assessment*:

NERC Group	Relationship	Contribution
Board of Trustees	NERC's Independent Board of Trustees	• Review the *2009 Long-Term Reliability Assessment* • Approve for publication
Planning Committee (PC)	Reports to NERC's Board of Trustees	• Review *2009 Long-Term Reliability Assessment* • Risk assessment of Emerging/Standing Issues
Operating Committee (OC)	Reports to NERC's Board of Trustees	• Review Assessment and provide comments to PC on operational aspects
Energy Ventures Analysis, Inc.	Third-Party Independent Consultant	• Provide assessment on North American natural gas, coal, and uranium conditions
Integration of Variable Generation Task Force (IVGTF)	Reports to the PC and OC	• Contribute to Standing Issues
Load Forecasting Working Group (LFWG)	Reports to RAS	• Develop load forecasting bandwidths
Data Coordination Working Group (DCWG)	Report to Data Coordination Subcommittee	• Develop data and Regional reliability requests • Data checking and validation
Eastern Interconnection Reliability Assessment Group (ERAG)	Independent Reliability Group	• Contributed to demand data validation effort
Reliability Metrics Working Group (RMWG)	Reports to the PC	• Developed System Risk Index
Resource Issues Subcommittee (RIS)	Reports to PC	• Develop Emerging Issues • Demand resources
Transmission Issues Subcommittee (TIS)	Reports to PC	• Develop Emerging Issues

APPENDIX II: 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[264]:

> **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.[265]
- 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.

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[264] See http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf more information about the Adequate Level of Reliability (ALR).

[265] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

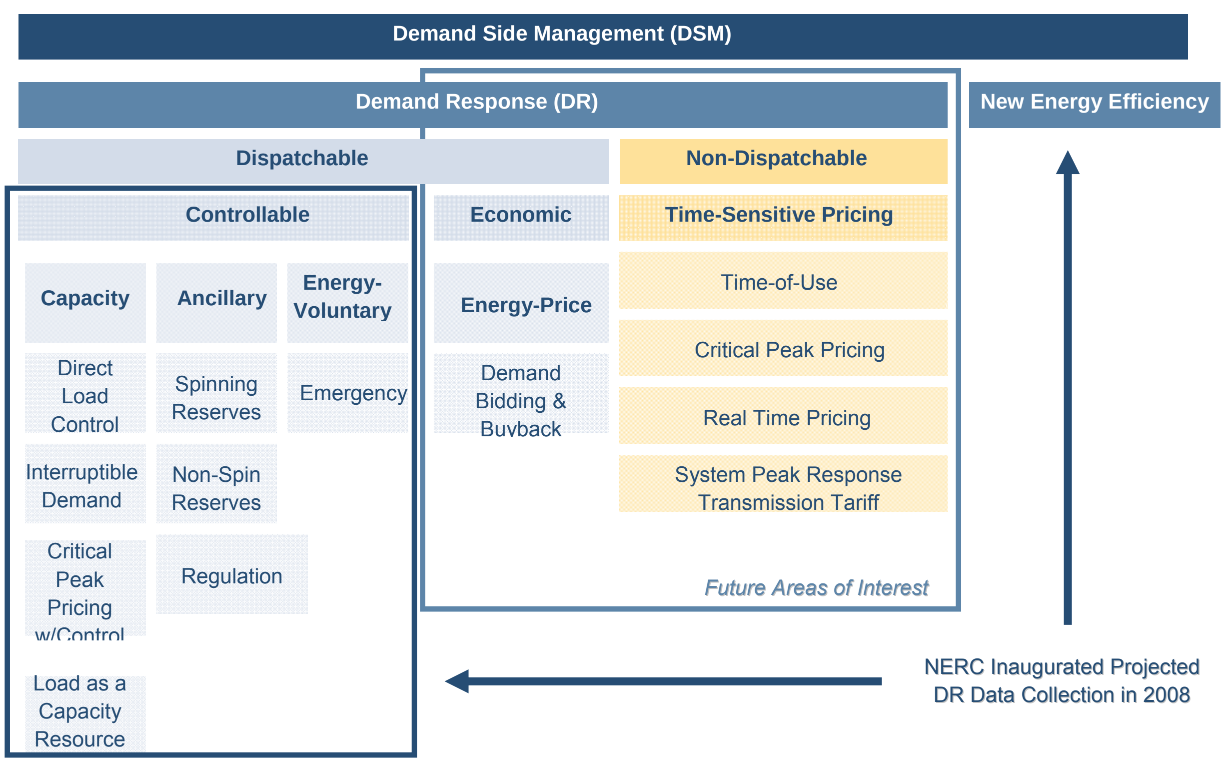
DEMAND RESPONSE CONCEPTS AND CATEGORIZATION

As the industry's use of Demand Side Management (DSM) evolves, NERC's data collection and reliability assessment need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected Energy Efficiency EE programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect Demand Response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use (See Figure Demand 1).

Note the context of these activities and programs is DSM, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. The Demand Response categories defined in *Terms Used in this Report* support Figure Demand 1

Figure Demand 1: Demand-Side Management and NERC's Data Collection



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. (MW)

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:

1. Corporate announcement
2. Entered into or is in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Conservation – *see* ***Energy Conservation***

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response**)** — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — *See* ***Contractually Interruptible***

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.[266]

Dispatchable (Demand Response**)** — Demand-side resource curtails according to instruction from a control center.

Disturbance Classification Scale — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Disturbance Event – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Economic (Controllable Demand Response**) —** Demand-side resource that is dispatched based on an economic decision.

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[266] 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

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[267] that is eligible to bid into a market or has been designated as a firm network resource.
3. Network Resource[268], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
4. Energy-only resources[269] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[270]
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[271] during the period of analysis in the assessment.

Existing-Certain & Net Firm Transactions – Existing-Certain capacity resources plus Firm Imports, minus Firm Exports. (MW)

Existing-Certain and Net Firm Transactions (%) (Margin Category) – Existing-Certain & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources **—** *See* ***Existing-Certain*, *Existing-Other*, *Existing, but Inoperable.***

Existing-Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future

[267] 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.

[268] 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.

[269] 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.

[270] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

[271] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

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:

1. A resource with non-firm or other similar transmission arrangements.
2. Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
3. Mothballed generation (that may be returned to service for the period of the assessment).
4. Portions of variable generation not counted in the Existing-Certain category (*e.g.*, wind, solar, etc. that may not be available or derated during the assessment period).
5. Hydro generation not counted as Existing-Certain or derated.
6. Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Expected implies that a contract has not been executed, but in negotiation, projected or other. These Purchases or Sales are expected to be firm.

2. Expected Purchases and Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Firm implies a contract has been signed and may be recallable.

2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also* ***Future, Planned*** *and* ***Future, Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.

2. Regulatory permits being approved, any one of the following:

    a. Site permit

    b. Construction permit

    c. Environmental permit

3. Regulatory approval has been received to be in the rate base.

4. Approved power purchase agreement.

5. Approved and/or designated as a resource by a market operator.

Future, Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future, Planned* and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

1. Be curtailed or interrupted at any time for any reason.

2. Energy-only resources that may not be able to serve load during the period of analysis in the assessment.

3. Variable generation not counted in the *Future, Planned* category or may not be available or is derated during the assessment period.

4. Hydro generation not counted in category *Future, Planned* or derated.

5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future, Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or firm) or other similar resource.

2. Where organized markets exist, designated market resource[272] that is eligible to bid into a market or has been designated as a firm network resource.

3. Network Resource[273], as that term is used for FERC pro forma or other regulatory approved tariffs.

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[272] 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.

[273] 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.

4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[274]

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.[275]

NERC's Bulk Power System Disturbance Classification Scale[276] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staff to determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's Bulk Power System Event Classification Scale is designed to classify bulk power system disturbances by severity, size, and impact to the general public.

<u>Operating Security Events</u> — Operating reliability events are those that significantly affect the integrity of interconnected system operations. They are divided into 5 categories to take into account their different system impact.

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

a. The loss of a bulk power transmission component beyond recognized criteria, *i.e.*, single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.

b. Frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.

c. Frequency above the High FTL more than 5 minutes.

d. Partial loss of dc converter station (mono-polar operation).

e. "Clear-Sky" Inter-area oscillations.

f. Intended and controlled system separation by proper Special Protection Schemes / Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.

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[274] Energy only resources with transmission service constraints are to be considered in category Future, Other.

[275] 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.

[276] http://www.nerc.com/page.php?cid=5%7C252

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.

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.

1. Public appeals to reduce demand.
2. Voltage reduction.
3. Interruption of non-firm end per contracts.
4. Demand-side management.
5. Utility load conservation measures.

Category A3: Firm load interruption imminent or in progress.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*i.e.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

Net Internal Demand: Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-dispatchable (Demand Response**) —** Demand-side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Non-Firm implies a non-firm contract has been signed.

2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity**) —** The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories – *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Prospective Capacity Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Prospective Capacity Resources. Replaced in 2009 with *Prospective Capacity Reserve Margin (%)* for NERC Assessments.

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

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

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally firm.

2. Provisional Purchases and Sales should be considered in the reliability assessments.

Purchases/Imports Contracts – *See* ***Transaction Categories***

Real Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Reserve Margin Level – *See* ***NERC Reference Reserve Margin Level***

Regulation (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes 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."[277] The government of Canada has a similar definition.[278] Variable generation is a subset of Renewable Energy—See ***Variable Generation***.

Renewables — *See* ***Renewable Energy***

Reserve Margin (%) — *See* ***Deliverable Capacity Reserve Margin (%)*** *and* ***Prospective Capacity Reserve Margin (%)***. Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Resource Adequacy Events — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

Sales/Exports Contracts – *See* ***Transaction Categories***

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response**)** **-** Rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

Total Internal Demand: The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structures with different unit prices for use during different blocks of time.

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[277] http://www1.eere.energy.gov/site_administration/ glossary.html#R

[278] http://www.cleanenergy.gc.ca/faq/ index_e.asp#whatiscleanenergy

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.[279] 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.

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

Abbreviations Used in this Report

A/C	Air Conditioning
AEP	American Electric Power
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
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