NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# 2009 Scenario Reliability Assessment

2009 - 2018

to ensure the reliability of the bulk power system

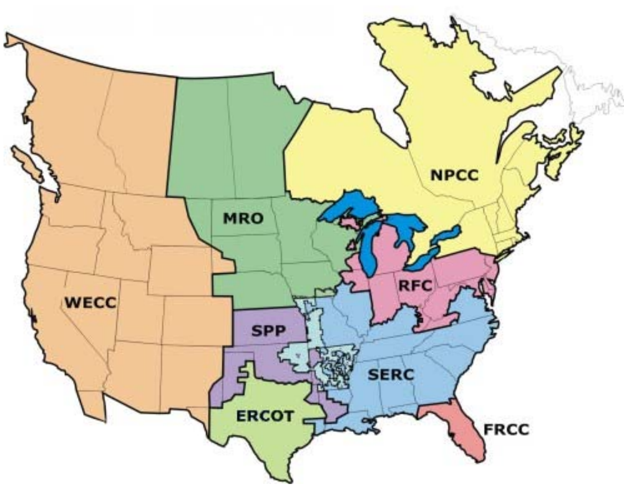
October 2009

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

# NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the United States Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight Regions, as shown on the map below (See Table A).[2] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México.




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

**Table A: NERC Regional Entities**

| | |
|---|---|
| **ERCOT**<br>Electric Reliability Council of Texas | **RFC**<br>Reliability*First* Corporation |
| **FRCC**<br>Florida Reliability Coordinating Council | **SERC**<br>SERC Reliability Corporation |
| **MRO**<br>Midwest Reliability Organization | **SPP**<br>Southwest Power Pool, Incorporated |
| **NPCC**<br>Northeast Power Coordinating Council, Inc. | **WECC**<br>Western Electricity Coordinating Council |

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all United States users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. Reliability Standards are also mandatory and enforceable in Ontario and New Brunswick, and NERC is seeking to achieve comparable results in the other Canadian provinces. NERC will seek recognition in Mexico once necessary legislation is adopted.

[2] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are Regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

# Table of Contents

# Executive Summary

NERC's *2009 Scenario Reliability Assessment* complements its *2009 Long-Term Reliability Assessment*, providing a view of how the ten-year forecast might change were a given hypothetical scenario applied. The projections contained in this report were based on a "bottom-up" approach, using data and perspectives from grid operators, electric utilities, and other users, owners, and operators of the bulk power system, as opposed to a "top down" modeling approach. The data is "rolled up" at a Regional level and presented by Region in this report. Each of the eight NERC Regions provided a detailed self-assessment for their respective Region, including high-level resource planning and operational challenges, transmission requirements, and changes to the generation mix.

The two scenarios studied in this report are:

- **Scenario 1: North American-wide Renewable Portfolio Standard —** A target of 15 percent of all energy must be met with new renewable resources. 33 percent of this target may be met by Energy Efficiency and Demand Response. Seven of the eight Regions chose this option.

- **Scenario 2: Another Similar Scenario of the Region's Choosing —** SERC chose this option, studying the integration of high-levels of new nuclear capacity.

Consistent with NERC's mission, this report is focused on assessing reliability impacts. This report does not represent actual plans or proposals, but outlines approaches in which scenario targets can be reached. Additionally, this report assesses the technical feasibility of these approaches and does not include such economic-driven assumptions such as, but not limited to, early unit retirement/replacement, transmission costs, and fuel costs.

Highlights of the *Scenario Reliability Assessment* include:

**Wind Power Forms the Base of Renewable Expansion**
Meeting the 15 percent target in the first *Scenario Case* would require the addition of 95,000 MW of new wind and solar resources (installed capacity), bringing the total to nearly 300,000 MW of installed, "nameplate" wind capacity—roughly 25 percent of the total installed, "nameplate" resource base projected in 2018. Significant operational challenges are expected as a result of this high influx of new variable resources.

The eighth Region, SERC, meets the *Scenario Case* targets with the addition of 12,500 MW of nuclear generation, nearly doubling the amount of nuclear capacity in the *Reference Case*. All Regions, with the exception of RFC, were able to meet *Scenario Case* targets by adding resources within their geographic area.

**Transmission Critical to Meeting Targets: 40,000 Miles Needed**

More than double the number of transmission miles specified in the *Reference Case* are required to meet targets in the *Scenario Case*. Three Regions (MRO, RFC, and SPP) cite the February 2009 Joint Coordinated System Plan (JCSP) as a base for this Scenario assessment, resulting in nearly 15,000 miles of additional transmission needed to ensure both the reliable and cost-effective integration of new renewable resources. While RFC plans to rely on imports from other Regions through transmission proposed in the JCSP, the remaining Regions plan to rely on resources within the Region to meet scenario targets in this assessment. This indicates there are multiple approaches to meeting the renewable energy scenario goal: while the JCSP proposes to construct renewable resources in the mid-section of the United States and transfer a portion of the energy to the Northeast via bulk transmission, NPCC has proposed to meet renewable energy targets using resources within the Region. Though the NPCC data provided to support this scenario reliability assessment did not identify specific transmission requirements, significant additions may still be required to integrate renewable resources within the Region, as highlighted in a recent draft report issued by ISO New England.[3] Proposals to fund coordinated system planning efforts in the United States are currently under review by the U.S. Department of Energy through the American Recovery and Reinvestment Act.

SERC plans to integrate new nuclear resources predominately at existing sites and requires only 717 miles of transmission in the scenario.

**More Energy Efficiency included in Load Forecasts**

Substantial increases in Energy Efficiency programs are included by some Regions to reduce their energy use. Over 1.5 GW of aggregated reductions was incorporated into load forecasts (reduced from the *Reference Case*), contributing to a reduction of peak demand.

**Increased Penetration of Variable Generation May Indicate a Need for Higher Operating and Planning Reserve Margins**

Over 95,000 MW of additional variable generation (wind and solar) is included to meet the *Scenario Case* targets. These resource additions cause Reserve Margins to increase in most Regions. However, with the integration of more variable generation, higher reserve margins may be needed to provide additional ancillary services to support the uncertainty and availability associated with these types of resources.

[3] http://www.nescoe.com/uploads/iso_eco_study_report_draft_sept_8.pdf

# Background Information for this Report

In December 2007, the NERC Planning Committee (PC) identified and prioritized various resource and transmission impact scenarios for Regional and NERC-wide evaluation, based on input from its subcommittees. As directed by the PC in December 2007, each Region was required to examine one of the following two Scenarios:

> **Scenario #1: Study accelerated integration of renewable resources[4]:** Around the world, renewable resources have become a significant portion of the generation mix. The available technologies have matured to the point where generation owners and system operators can generally meet federal, state, and provincial renewable energy mandates, although penetration may be limited by system integration issues. For example, weather patterns of the Region/subregion, the variety of renewable sources, the existing generation mix, and the bulk power system transfer capability with neighboring areas all influence the level of penetration that can be achieved. Another consideration is ancillary services and system re-dispatch needed to support reliable operation of the system given the level of renewables integrated.
>
> For this Scenario, the Regions assessed meeting 15 percent of total energy with new renewable resources, above the *Reference Case* values, with no more than a total of five percent made up from Energy Efficiency. The base year for calculating energy was set as 2008 to provide a common reference value. The addition of renewable resources may be ramped at a rate that can be integrated into the system while sustaining bulk power system reliability throughout the ten-year period.
>
> **Scenario #2: Scenario selected by the Region/subregion for study in 2009:** If Scenario #1 would have had little or no impact on a Region/subregion, then Scenario #2 could be evaluated. The Regions were expected to select a Scenario that significantly impacts supply mix and electricity purchases or sales in the studied Region. The emerging issues identified in the *2007 Long-Term Reliability Assessment* are potential candidates for this alternate Scenario analysis. The assessment and detail required in the analysis were consistent with the framework provided for Scenario #1.

Based on this guidance, Regions selected suitable Scenarios to study and provided a summary of those plans. While all Regions indicated the ability to compare peak capacity changes and identify operational challenges associated with the Scenario, some Regions specified limitations in providing comparable data (see Table 1).

---

[4] The U.S. Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes can not be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource." The government of Canada has a similar definition. http://www1.eere.energy.gov/site_administration/ glossary.html#R

**Table 1: Regional plans for the 2009 Scenario Analysis**

| Region | Scenario | Compare to *Reference Case* | Annual Peak or Point in Time | Energy Fuel Mix | Miles of Transmission | End Status |
|---|---|---|---|---|---|---|
| ERCOT | Wind resources for 15 percent of new energy | Yes | Annual peak to 2018 | Yes | Yes | Completed |
| FRCC | Renewable resources for 15 percent of new energy | Yes | Annual Peak to 2017 | Yes | Yes | Completed |
| SERC | Southeast Generation Fuel Shift | Yes | Point in Time 2019 | No | Yes | Completed |
| WECC | Renewable resources for 15 percent of new energy | Will compare capacity mix | Point in Time 2017 | Yes, but can't compare energy to *Reference Case*, will compare by fuel | Approximate | WECC did not use the original 2008 LTRA as a *Reference Case* |
| MRO | | Yes | | Yes | Yes | Completed with JCSP Study results |
| NPCC | Wind resources contributing to at least 15 percent of new energy | Yes | Point in Time 2018 | Yes | Yes | New York and New England did not use the JCSP for this Scenario |
| RFC | | Yes | | Yes | Yes | Completed with JCSP results |
| SPP | | Yes | | Yes | Yes | Completed with JCSP results |

As indicated in the table above, several Regions rely upon the Joint Coordinated Study Group's Joint Coordinated System Plan (JCSP) for their analysis. A review of this plan is located in the *Joint Coordinated System Plan* section of this report.

The *Reference Case* for comparison of the Scenario results was developed from NERC's *Long-Term Reliability Assessment*, which includes data and information on projected summer and winter electricity supply and demand conditions for a ten-year period, along with reliability self-assessments prepared by each Regional entity. The *Reference Case* incorporates known policy and regulation changes expected to take effect throughout the studied timeframe assuming economic growth, weather patterns, and system equipment behaviors are as expected, usually based on historic performance trends (see Table 2). Half of the Regions used the *2008 Long-Term Reliability Assessment* as their *Reference Case*.[5] The remainder of the Regions used the

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

*2009 Long-Term Reliability Assessment* (to be published as a companion document to this report).[6]

**Table 2: *Reference Case* used for the 2009 Scenario Analysis**

| Region | *Reference Case* |
|---|---|
| ERCOT | *2009 Long-Term Reliability Assessment 2009-2018* |
| FRCC | *2008 Long-Term Reliability Assessment 2008-2017* |
| MRO | *2008 Long-Term Reliability Assessment 2008-2017* |
| NPCC | *2009 Long-Term Reliability Assessment 2009-2018* |
| RFC | *2008 Long-Term Reliability Assessment 2008-2017* |
| SERC | *2008 Long-Term Reliability Assessment 2008-2017* |
| SPP | *2009 Long-Term Reliability Assessment 2009-2018* |
| WECC | *2009 Long-Term Reliability Assessment 2009-2018* |

Regions proposed study outlines which were submitted to the PC in June 2008 and approved. Regional self-assessments and the associated data were provided to NERC in June 2009. Subsequently, the Reliability Assessment Subcommittee peer-reviewed the results and enhancements of the Regional reliability assessments and data were made to address the subcommittee's comments.

[6] For more information on the terms used in this report, supply definitions, reliability concepts, assessment methods, and background material, refer to the *2008 Long-Term Reliability Assessment* and the *2009 Long-Term Reliability Assessment at* http://www.nerc.com/page.php?cid=4|61

# Scenario Reliability Assessment Summary

In order to meet the Scenario targets, the Regions made significant changes to their resource mix. The following Key Scenario Highlights from assessing the results during the study period are:

### Scenario Highlights

- Wind Power Forms the Base of Renewable Expansion
- Transmission Critical to Meeting Targets: 40,000 Miles Needed
- More Energy Efficiency Included in Load Forecasts
- Increased Penetration of Variable Generation May Indicate a Need for Higher Operating and Planning Reserve Margins

### Demand

For the *2009 Scenario Reliability Assessment*, no changes were made to the peak demand forecasts from the *Reference Case*. Many existing and proposed Renewable Portfolio Standards (RPS) include provisions to incorporate energy savings from Demand Side Management (DSM), programs. While DSM deployment can effectively reduce energy use through Energy Efficiency, energy from Demand Response also can contribute to reduced energy use. Regions were able to incorporate up to 5 percent of their energy target using DSM to meet the 15 percent target for Scenario #1.

**Table 3: Energy Efficiency with Scenario Peak Demand Reductions (MW)**

| | Reference Case Total Internal Demand | Scenario Case Total Internal Demand | Energy Efficiency Reductions | Percentage Reduction of Total Internal Demand |
|---|---|---|---|---|
| **ERCOT** | 76,134 | 76,134 | - | 0.0% |
| **FRCC** | 59,576 | 59,264 | *(312)* | -0.5% |
| **MRO** | 58,668 | 58,068 | (600) | -1.0% |
| **NPCC**** | | | | |
| **New York** | * | 35,658 | - | - |
| **New England***** | 30,960 | 30,960 | (781) | -2.5% |
| **Maritimes** | 5,765 | 5,765 | - | 0.0% |
| **Ontario** | 22,497 | 22,497 | - | 0.0% |
| **Quebec** | 40,687 | 40,687 | - | 0.0% |
| **RFC** | 208,600 | 208,600 | - | 0.0% |
| **SERC** | 252,892 | 252,892 | - | 0.0% |
| **SPP** | 49,696 | 49,696 | - | 0.0% |
| **WECC** | * | 177,354 | - | - |
| **TOTAL** | **705,565** | **822,751** | **(1,693)** | **-0.2%** |

* The *Reference Case* Total Internal Demand for the New York subregion and WECC Region are not comparable to the *Scenario Case* Total Internal Demand. Energy Efficiency is embedded in demand forecasts and was not explicitly reported in terms of peak demand reduction (MW).

** NPCC provided demand projections by subregion.

*** The New England subregion contributed Energy Efficiency as a supply-side resource, which does not reduce Total Internal Demand.

Therefore, as part of this *Scenario Reliability Assessment,* some Regions reduced their energy use (MWh) by incorporating more Energy Efficiency into their load forecast, resulting in a reduction of peak demand (MW). For example, NPCC's New England and New York subregions used Energy Efficiency to reduce their *Reference Case* energy forecast by 5 percent. While the effects of increased Energy Efficiency do not translate into significant peak reductions, growth in Energy Efficiency is likely to occur if RPS requirements cannot be reached with renewables alone. The additional reductions identified in this Scenario are both Regionally specific and minor in magnitude. In many cases, Regions did not incorporate the potential reductions offered through Energy Efficiency for the *Scenario Case*.

## Generation

To achieve study targets for all Regions combined, nearly 115,000 MW of additional installed generation would be needed during the assessment period[7] (Figure 1). Because over 80 percent of this new installed capacity is variable generation[8] (wind and solar), only 48,000 MW contribute to meeting peak demand.

With large increases in variable generation, additional ancillary services would be needed to maintain bulk power system reliability. In addition, changes to the level and type of ancillary services required to support operational reliability with high penetrations of variable resources might also drive changes to the mix of installed and planned resources. For example, in Ontario, additional gas-fired generation (1,000 MW) would be needed to support the variability of wind resources.[9] Further, some Regions replaced Proposed generation, identified in the *Reference Case*, with renewable resources to meet Scenario targets. For example, in FRCC, 4,500 MW of gas-fired generation was replaced with renewable resources (solar and biomass). RFC also replaced 5,500 MW of fossil-fired generation with 25,600 MW of installed, "nameplate" wind capacity.

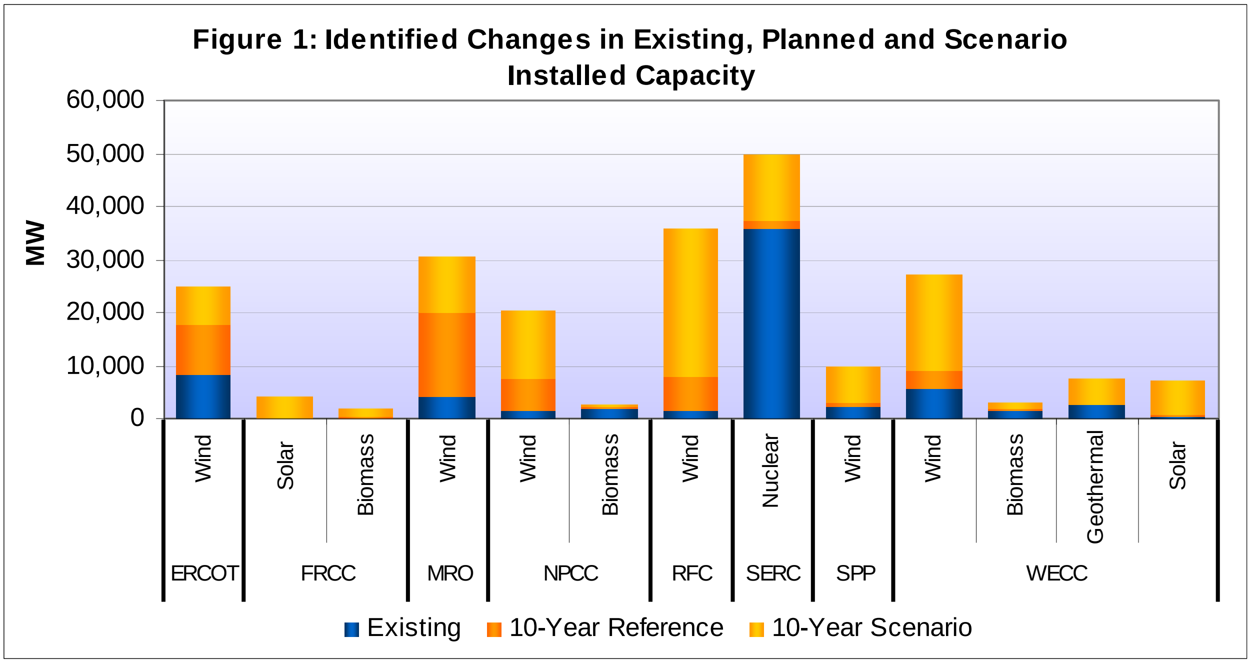
Additionally, 15,000 MW of biomass and geothermal generation was also incorporated to meet Scenario #1 targets. While these types of generation are renewable resources, their generation profile does not display the same variability or availability as wind and solar generation. Increases in these kinds of alternative renewable generation are expected in Regions where wind and sunlight are not optimal for generating electricity. In WECC, a 2,500 MW increase in geothermal generation is identified and could be used as a reliable baseload generation resource.

Retirements, mothballing, and changes to planned resources in the *Reference Case* would likely occur in response to the addition of high levels of renewable resources (Scenario #1), though the exact changes are dependent on market and regulatory mechanisms. Therefore, much of the existing resources in the *Scenario Case* would remain unchanged from those in the *Reference Case*.

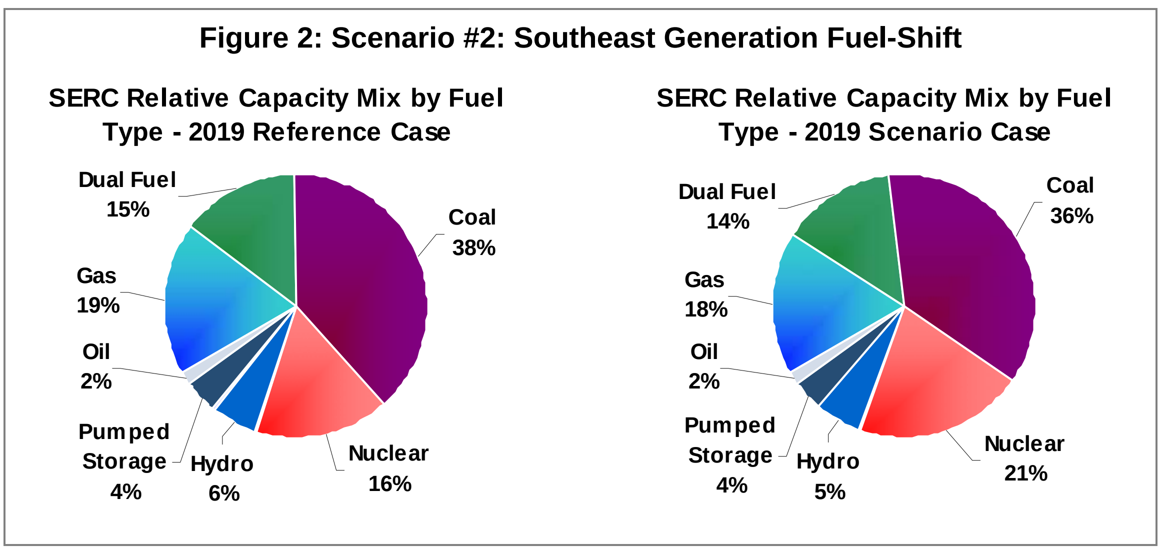
[7] Increases in generation are compared only to the Future/Planned resources in the *Reference Case*. Conceptual resources were not used in this comparison.

[8] There are two major attributes of variable generation that notably impact bulk power system planning and operations: variability and uncertainty. Wind and solar generation are the most significant sources of variable generation on the bulk power system. For more information see: *Accommodating High Levels of Variable Generation*: http://www.nerc.com/files/IVGTF_Report_041609.pdf

[9] The increase in gas-fired generation is not shown in Figure 1.




In Scenario #2, 12,500 MW of nuclear generation is projected to shift the overall fuel mix in SERC, as it would become the second largest contributor to generating capacity, Figure 2.




## On-Peak Capacity Transactions

No Regional transaction adjustments were made from the *Reference Case* to the *Scenario Case*, except in RFC, which increased net import by 2,300 MW. Firm capacity transactions were unchanged from the *Reference Case*. However, according the results from the *2008* and *2009 Long-Term Reliability Assessments*, large amounts of variable generation are projected to come on line within the ten-year assessment period.[10] If these resources do come on line, Regions with higher levels of variable generation, such as SPP and MRO, may need access[11] to neighboring Regions more frequently and at greater magnitudes to maintain reliability[12]. As such, more firm transmission contracts across Regional boundaries may be expected.

## Transmission

Over 40,000 miles of transmission is needed for the *Scenario Case* when compared to the *2008/2009 Reference Case.* Almost half of these transmission miles support the integration of additional resources identified in the *Scenario Case* (Table 4). With the large amount of variable generation included in the *Scenario Case*, transmission would be a key component to accommodating new resources, linking geographically remote generation to demand centers.

Additionally, the incremental transmission miles (over 18,000 miles) required for the *Scenario Case* is understated as some Regions noted that significant additional transmission would be needed beyond this amount, but some were unable to provide quantitative estimates.[13] Upgrades to existing transmission were also identified to increase transmission capacity. For example, in FRCC, few additional lines would be needed when compared to *Reference Case* projections; however, 132 miles of 230 kV would need to be upgraded.

**Table 4: Existing, Reference, and Scenario Case: Circuit Miles > 200kV**

| | Existing as of Base Year in Reference Case | Existing and Planned Transmission in Reference Case | Total Transmission in Scenario Case | Percentage Increase from Base Year in Reference Case |
|---|---|---|---|---|
| **ERCOT** | 8,917 | 13,032 | 14,020 | 57.2% |
| **FRCC** | 7,201 | 7,789 | 7,803 | 8.4% |
| **MRO** | 22,632 | 26,289 | 33,505 | 48.0% |
| **NPCC** | 36,100 | 37,775 | +39,571 | 9.6% |
| **RFC** | 26,203 | 27,828 | 33,368 | 27.3% |
| **SERC** | 32,295 | 34,724 | 35,440 | 9.7% |
| **SPP** | 9,063 | 9,877 | 11,701 | 29.1% |
| **WECC** | 70,435 | 78,527 | +78,527 | 11.5% |
| **TOTAL** | **212,846** | **235,841** | **253,935** | **19.3%** |

## Operational Issues

In the 15 percent renewable energy Scenario (Scenario #1), Regions identified several key issues the industry would face when integrating high levels of renewable generation. Solar and wind

[10] For the *2008 Long-Term Reliability Assessment*, over 150,000 MW of Potential wind was identified for the ten-year period.

[11] "Access" here refers to transfer capabilities, reserve sharing, cross-regional coordination, and other mechanisms to facilitate bulk power transfer.

[12] For those Regions using the JCSP study for this scenario assessment, the assumption of delivering power to the east was declared.

[13] WECC and the New York and New England subregions of NPCC were unable to provide an estimate of the amount of additional transmission that would be needed to integrate proposed generation.

generation pose significant operational challenges due to inherent variability and uncertainty.[14] The following operational issues were considered the most important:

1. **Minimum Generation Limits During Light Load Conditions**

   Large additions of variable generation may present a challenge in managing the generation fleet output for day-ahead unit commitment. For example, system demand may fall below the aggregate minimum output of existing conventional steam plants. Increased cross-Regional communication and coordination would be needed to alleviate these potential over-generation scenarios. Because renewable portfolio standards require meeting minimum energy levels, operators must balance these requirements without affecting bulk power system reliability.

2. **Increased Ramp Requirements and Out-of-Phase Ramping**

   Ramps are the increase or decrease of generation output. Wind generation ramps can have an inverse correlation (out-of-phase ramping) to daily load profiles resulting in the need for additional reserves. Operators may need to closely monitor the system and introduce operational resources, such as Demand Response or energy storage, that support the variability and ancillary services needed to reliably support integration. Additionally, enhanced operational measures, in particular re-dispatch of conventional generation and dynamic curtailment/dispatch of wind resources, can mitigate ramping impacts.

   Photovoltaic (PV) generation ramps have different characteristics than wind generation ramps. Since there are no moving parts, there is no inertia, resulting in significant ramps when fuel (sunlight) becomes obscured by clouds. PV generation can experience variations in output of +/- 50 percent in a 30 to 90 second time frame and +/- 70 percent in a five to ten minute timeframe.[15] These ramps in PV generation output can occur many times in a single day due to varying weather conditions. Managing the energy contributions of solar resources with conventional generation represents a significant challenge for reliable integration. The ability to rely on faster-acting resources may reduce these impacts and enable large-scale integration.

3. **Accurate Day-Ahead and Hourly Wind Forecasting**

   Predicting the output level of wind generation for a future time period (e.g., day ahead, hour ahead, etc.) is vital to maintain bulk power system reliability. Because wind generation is driven by the same physical phenomena as weather, the uncertainty of wind generation at a future hour (even the next hour) may be significant. As wind generation penetration levels increase, the forecast accuracy becomes essential to operate a reliable system. Additionally, accurate wind forecasts and timely updates are necessary in order to incorporate wind generation into the Day Ahead markets.

[14] http://www.nerc.com/files/IVGTF_Report_041609.pdf
[15] NERC Special Report: *Accommodating High Levels of Variable Generation* (Page 27).

### 4. Access to Additional Operating Reserves

Operating reserves may need to increase with large quantities of variable generation online. Until more operating experience is gained, industry may require more operating reserves be available in the day-ahead market. The variability and ramping characteristics of wind turbine and solar generation output may also require access to additional spinning and operating reserve margins. Day-ahead ancillary service markets must be closely coordinated with wind forecasts and real-time monitoring of wind output.

For the Southeast Generation Fuel-Shift Analysis in SERC, operational challenges would be somewhat similar to those presented above: 1) Increased reserve requirements with larger units[16], 2) As generation is more concentrated at existing sites, common modal failures and multiple contingency losses could result, and 3) Load-following technology would be necessary to increase the operational flexibility of a system with many high-capacity units.

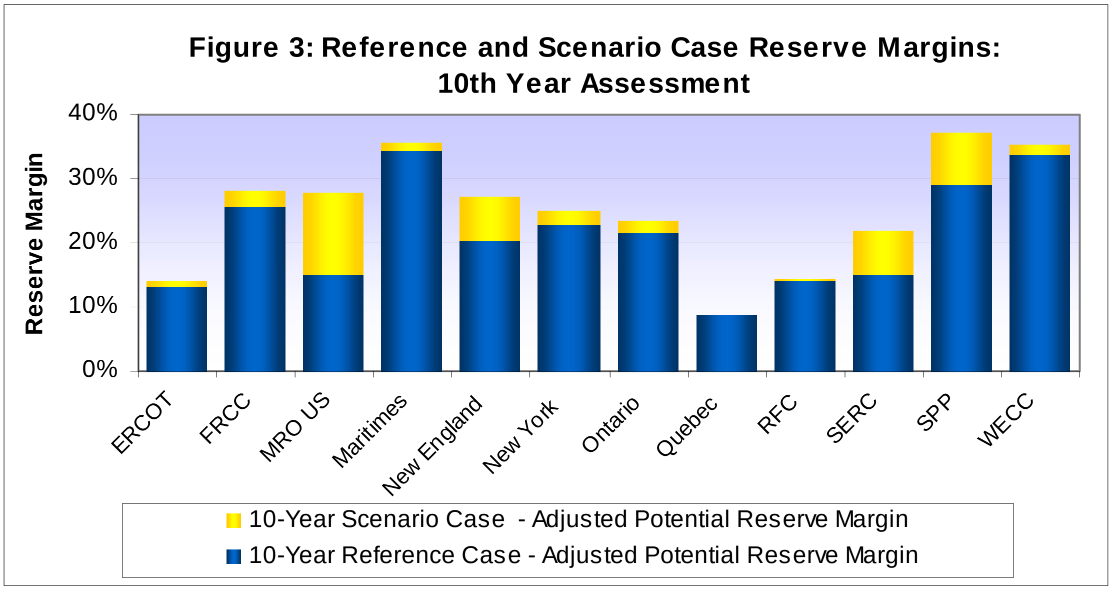
## Reliability Assessment

Overall, Regional Reserve Margins[17] appear to increase (Figure 3). Adjusted Potential Resources for the *Scenario Case* are compared to the *Reference Case*. Unit mothballing or retirements were not fully included in this Scenario. Because of this, reserve margins presented in this assessment may be overstated due to economic decisions that may occur. However, as previously mentioned, some Regions replaced projected resources with renewable resources to meet Scenario targets. Consistent with observations made in the *Generation* section, Reserve Margins are only slightly increased in FRCC and RFC due to the replacement of planned generation identified in the *Reference Case* with renewable resources for the *Scenario Case*. Additionally, slight increases were also observed in ERCOT and the Maritimes, where less than 1,000 MW of expected on-peak capacity was added.

The largest incremental increases are found in MRO-US, the New England subregion in NPCC, SERC, and SPP. An overall increase in expected on-peak capacity is the primary driver for higher Reserve Margins.

[16] Larger units may increase what is identified in the Balancing Area as the most severe single contingency.

[17] "Reserve" margins in this report represent margins calculated for planning purposes (planning Reserve Margins) not operational reserve margins which reflect real-time operating conditions.




Based on the Regional Scenario Self-Assessment, it is likely that Reserve Margins would increase with the addition of more variable generation.[18] Due to low expected on-peak availability, variable generation cannot entirely replace existing conventional generation due to operational considerations (i.e., variability), thus driving the need for higher planning and operating reserve margins as resources are added. Further, this growth in variable generation could increase requirements for conventional generation or transmission as the need for access to additional ancillary services may be needed to maintain reliability.

**NERC Actions**

- Continue to investigate reliability implications of large fuel-mix shifts due to Renewable Portfolio Standard requirements.
- Consider performing energy assessments as more renewable resources are integrated into the bulk power system.
- NERC working groups and task forces should continue to investigate planning and operational requirements needed to manage the integration of variable generation.
- Regional coordination and data collection efforts should be enhanced as renewable mandates emerge. NERC will continue to advise the industry regarding reliability impacts and relevant recommendations to support planning and operations.

[18] The New York subregion Reserve Margin in Figure 3 is 25.1 percent. This reflects a derate of total installed wind capacity (from 8,000 MW to 800 MW). The New York subregion calculates a different Reserve Margin based on total installed capacity (See the NPCC-New York Self Assessment).

# Regional Scenario Self-Assessments

## ERCOT Highlights

A *Scenario Case* assessment was performed on the ERCOT Region for the 2009 NERC *Long-Term Reliability Assessment*. In this *Scenario Case*, incremental wind energy resources sufficient to provide an additional 15 percent of the energy requirements in the ERCOT Region, relative to the energy produced by wind resources in the Region during 2008, were assumed to be added by 2018.

The *Scenario Case* was based upon studies completed by ERCOT in 2008 for the Public Utility Commission of Texas (PUCT) as a part of the PUCT's designation of Competitive Renewable Energy Zones (CREZ). This *Scenario Case* assumes a total of 24,859 MW of wind generation is online by 2018, whereas the *Long-Term Reliability Assessment Reference Case* assumes 10,558 MW for 2018. This amount of installed wind capacity has the potential to produce approximately 18 percent of the energy requirements of the 2018 load in the ERCOT Region.

The *Scenario Case* assessment does not include a quantitative analysis of the system operational requirements, but qualitatively addresses some of the issues that would need to be addressed at this level of wind penetration.

In order to provide adequate transmission capacity for the wind generation resources included in this *Scenario Case*, 300 miles of new 345 kV right-of-way and 360 miles of new HVdc right-of-way were added to the already-significant transmission additions included in the *Long-Term Reliability Assessment Reference Case*.

Incorporating the additional wind generation results in an adequate reserve margin through 2014, the same year identified in the *Reference Case*; however, this assessment did not evaluate any other changes that might occur to the existing installed fleet of generation in economic response to the additional wind generation.

## FRCC Highlights

FRCC performed a qualitative analysis of the 2017 renewable scenario to determine the impact of the changes to legislation regarding Renewable Portfolio Standards to FRCC Region's bulk power system. The governor of the State of Florida has signed an executive order establishing immediate actions to reduce greenhouse gas emissions within the state. However, the State Legislature has not acted on proposed legislation leaving the Florida without a Renewable Portfolio Standard.

The results of the quantitative analysis indicate that in order to develop the *Scenario Case*, approximately 70 percent of the renewable resources expected by 2017 are expected to come from Solar PV and the remaining 30 percent from biomass. This level of renewable resources is expected to deliver approximately 12 percent of the total energy. The remaining 3 percent is expected from Energy Efficiency programs promoting conservation.

The results of the qualitative analysis show that in order for FRCC to meet an additional 15 percent of Net Energy for Load from renewable resources, 31 miles of new transmission would need to be constructed and 178 miles would need to be upgraded to ensure an adequate and reliable bulk power system. Additional transmission facilities may be required in order to interconnect the proposed renewable resources. The amount and type of interconnection facilities that may be required can be extensive depending on siting locations relative to the existing transmission network.

## MRO Highlights

This assessment quantifies the amount of wind generation that would be required to serve an additional 15 percent of energy within the MRO footprint in 2017, above and beyond the existing renewable generation capabilities. It also reports on the amount of wind generation and transmission reinforcement that could materialize within the MRO footprint based on the results of the multi-regional study referred to as the Joint Coordinated System Plan (JCSP) study of 2008. This study takes into account the Interconnection Queues and Renewable Portfolio Standards (RPS) for most of the states in the Eastern Interconnection and describes what the Bulk Electric System might require if 20 percent of the JCSP footprint energy in 2024 is served by wind generation. This large scale multi-regional study of variable generation installed across the Eastern Interconnection is the most comprehensive to date and is being referenced by several Regional Entities in this report.

Wind power development in the Upper Midwest continues to be carried out at a very rapid pace. Wind generation nameplate capacity within the MRO Region increased from approximately 4,000 MW in June 2008 to about 6,000 MW in June 2009, a 50 percent increase in one year. In this assessment, the MRO focuses its attention on the operational issues, as there have been indications that operating the system with a significant amount of wind generation would be a challenge.

As the result of this assessment, the MRO Scenario Assessment Task Force has found the following:

- Given the wind-resource richness of the Upper Midwest, the RPS mandates in a number of states within the MRO footprint, and the production tax credit in effect through 2012, it is likely that the total wind resource nameplate capacity within the MRO-US would reach the level estimated in this assessment—32,10 MW in 2017, capable of serving 41.7 percent of the subregion’s 2017 energy.

- System planners and operators must be aware of the operational issues that come with such a large amount of wind generation. These issues are important to identify up front, since wind generation is routinely being installed more quickly than the transmission that is needed to deliver it to distant load centers.

- There would be a need for tremendous transmission facility additions to accommodate the added wind resources. However, at this time, there are no plans that indicate which types of facilities or how and when any of them would be constructed.

# NPCC Highlights

The scenario analysis for the NPCC Region, as part of the NERC *2009 Long Term Reliability Assessment*, assumed incremental renewable resources to provide an additional 15 percent (a maximum of 5 percent made up from Energy Efficiency) of the requirements for the year 2018 for the Reliability Coordinator Balancing Authorities within NPCC (Maritimes, New England, New York, Ontario and Québec). The comparisons are judged against the *Reference Case* and data presented in the *2009 Long Term Reliability Assessment*. The Québec area is an asynchronous Interconnection with over 90 percent of its energy produced by renewable resources over the ten year time frame of the *Long-Term Reliability Assessment*, and, its future energy production would continue to be sourced through renewable resources. In the remaining four areas, a total of 15,230 MW of wind generation is assumed to be in service:

- Maritimes 2,350 MW
- New England 3,380 MW
- New York 8,000 MW
- Ontario 1,500 MW
- Québec 0 MW

Upon the assumption of this addition of renewable capacity, planning reserve margins increase significantly for the study year of 2018.

Because of the variable characteristics of wind generation, each of the NPCC areas is addressing the operational challenges of integrating large amounts of intermittent resources. These include increased periods of operation at minimum load and the need for increased regulation and load following characteristics.

The *Scenario Case* reports no specific bulk power transmission additions. However, within the NYISO and ISO-NE, the planning process would identify and integrate renewable resources into the system; the NYISO has also recognized some portions of the system may realize local constraints which could result in some amount of undeliverable wind energy. The IESO expects that new 500 kV transmission west of its London substation would be needed to support the addition of the proposed wind resources. The New Brunswick System Operator estimates that 400 miles of 138 kV construction would be required. Increased system voltage support in many local areas would also be necessary.

Although the incorporation of significant amounts of renewable capacity would be a challenge, it is believed that these resources would be reliably integrated.

# RFC Highlights

Reliability*First* Corporation (RFC) has relied solely upon the recently completed 2008 Joint Coordinated Study Plan (JCSP)[19] for this Scenario analysis assessment. The JCSP effort covered most of the Eastern Interconnection including the entire RFC footprint and studied two cases, a Reference *Scenario Case* and a 20 percent Wind Energy *Scenario Case* for the 2024 study year. This RFC Scenario Assessment used the Reference Scenario data for 2018 as described in the JCSP study for its *Reference Case* and used the 20 percent Wind Energy Scenario data for 2018 as described in the JCSP study for its *Scenario Case*. Small adjustments in the JCSP data were made to match with the RFC 2008—2017 *Long-Term Reliability Assessment* data, with the JCSP data used for 2018. The most significant adjustment was to the 2018 peak demand. The JCSP demand and Net Energy for Load (NEL) for 2018 resulted in a low load factor. Since the scenario analysis is heavily influenced by the energy assumptions, RFC used the JCSP NEL for 2018 with a load factor in line with the 2008—2017 RFC *Long-Term Reliability Assessment*. This results in lower Total Internal Demand (TID) and Net Internal Demand (NID) peaks in this scenario analysis than the peak demand in the JCSP study.

The JCSP study also included sufficient resources to maintain resource adequacy throughout its study. Since this scenario analysis contains equivalent capacity resources with a peak demand that is lower than the JCSP study, the 23 percent reserve margin projected for both the reference and wind *Scenario Cases* in this analysis is not surprising.

One purpose of this scenario analysis is to determine, in general, the impacts of large amounts of wind power on the system as a result of renewable portfolio standards. Three significant impacts have been identified. First, there is an urgent need to better forecast wind speeds that result in a more accurate hourly wind generation profile. Second, there would be an increasing need to effectively manage and possibly curtail wind generation during light demand periods. Third, there may be a need to increase daily operating reserve requirements in order to have the flexibility to accommodate ramp rates and other contingencies related to a variable wind generation profile.

The JCSP study developed a transmission overlay to enable the large-scale transfer of power between different Regions of the country. The JCSP study did not evaluate the additional underlying lower voltage transmission network that would be necessary to connect the rest of the system.

[19] See www.jcspstudy.org

# SERC Highlights

Detailed discussion of the *2008 Long-Term Reliability Assessment* (*Reference Case*) for the comparisons presented here can be found in the introductory sections of this report. Because there is little or no penetration of type of resources offered in Scenario #1 option of the NERC Scenario Analysis in the SERC Region, the utilities in the SERC Region opted for Scenario #2 (a scenario of the Region's choosing). The SERC Region selected a scenario, which significantly impacts supply mix in the SERC Region in 2019 by adding significant amounts of carbon-neutral generation. The SERC Long-term Study Group (LTSG) conducted this study to evaluate future performance of the interconnected electric transmission systems within the SERC Region for the 2019 summer peak season. This study was initiated in July 2008, at the direction of the SERC Regional Studies Steering Committee (RSSC), as part of a continuing effort to:

1. Accomplish the objectives of the various reliability agreements among SERC member systems by examining the resulting transfer capability, and
2. Respond to the data request of NERC for a Long-term Reliability Assessment *Scenario Case* to supplement the *Reference Case*.

The primary focus of this scenario is the addition of substantial generation (both nuclear and fossil but primarily nuclear) beyond the *Reference Case*; over 13,000 MW to selected points in the Region.

The SERC Reliability Review Subcommittee (RRS) proposed and received approval by the NERC Planning Committee (PC) to evaluate potential Southeast Generation Expansion as the Region's *Scenario Case*. The prospective generation plants within the SERC Region would introduce large amounts of capacity in only a few sites on the system (resulting in a lumpiness effect), requiring some bulk power transmission expansion. While the local area impacts of each plant would be captured by the required System Impact Studies performed by the respective Transmission Providers to which these plants would be interconnected, joint-studies in the future are expected to evaluate system reliability impacts of all the proposed and prospective plants simultaneously.

## SPP Highlights

Southwest Power Pool (SPP) will discuss wind penetration in this *Scenario Reliability Assessment*. Along with other entities in RFC, MRO, NPCC,[20] and SERC, SPP participated in the Joint Coordinated System Plan[21] (JCSP) to examine the impact of wind penetration in the western part of the Eastern Interconnection, develop a conceptual transmission plan for 2024, and create a reliability assessment for 2018. SPP has used the JCSP study as a guideline to discuss this *Scenario Reliability Assessment*.

JCSP study results indicated that for the 20 percent wind energy *Scenario Case*, SPP would be an exporting Region with over 8,000 MW of wind energy. To accommodate this wind energy, about 1,800 miles of 765 kV transmission lines and 18 transformers would be needed to reinforce the lower voltage system. In anticipation of this scenario, SPP is planning to implement real-time operational tools to manage operational issues expected in its Region.

[20] ISO New England Inc. (ISO-NE) and the New York ISO (NYISO) were not signatories to the JCSP.
[21] http://jcspstudy.org/

## WECC Highlights

The Western Electricity Coordinating Council (WECC) studied the effect of one scenario of 15 percent renewables generation (by energy) in the Western Interconnection in 2017. The scenario that was studied was not the only one that could have been constructed and other scenarios could lead to different specific results. However, the study, along with other efforts underway in WECC, did lead to several general overall conclusions.

1. High levels of renewable generation, because of their spatial location relative to Western load centers, can lead to stresses on the capacity of the transmission system and the need to increase that capacity to deliver the generation to load.
2. High levels of variable renewable generation can raise significant operating challenges that can require new institutional arrangements and business practices in order to economically maintain the ability of Balancing Authorities (BA) to meet NERC and WECC reliability standards.
3. While high levels of renewable generation per se do not raise adequacy issues, high levels of variable renewable generation, raise two kinds of adequacy issues.
    - First, it is important to evaluate how much variable generation can reliably be expected to contribute to system peak.
    - Second, high penetrations of variable generation can require significant amounts of flexible resources to integrate that variable generation into the grid. Only resources with the ability to ramp up and down quickly — such as hydro, combustion turbines, storage resources, and certain demand-side management resources — have the appropriate attributes to be able to integrate wind, solar photovoltaic, and other variable renewable resources into the grid.
4. High levels of renewable generation, typically with very low operating costs, would have a significant effect on generation and fuel use by those units typically on the margin (i.e., gas generation) in the Western Interconnection. This could raise issues of gas procurement and scheduling, though WECC was unable to study those issues. Natural gas supplies delivered through intra-state pipeline systems offer the greatest operating flexibility when such systems are connected to gas storage projects. The areas in WECC that plan to follow variable renewable output with gas-fired generation otherwise may need to have natural gas storage infrastructure built or inter-state pipelines would have to accept day-after or real-time schedule changes.

WECC and its members (utilities, state and provincial entities, independent generators, and others) are addressing the issues raised by these conclusions.

- WECC has an extensive study program ongoing under the guidance of the Transmission Expansion Planning Policy Committee (TEPPC). This work is performed in coordination with Western Subregional Planning Groups (SPG) and individual transmission providers to evaluate long-range needs for transmission expansion in the Western Interconnection. The coordination among the three levels of study efforts, interconnection-wide to individual transmission provider, and the relationship of these groups and study efforts to each other and to the providers' responsibilities under their Open Access Transmission Tariff is described in a document posted on the WECC Web site.[22]

- In addition to the large number of past and ongoing operating issue studies being conducted by WECC members, WECC recently created the Variable Generation Subcommittee (VGS) to coordinate pertinent WECC study efforts and the dissemination of results (both WECC's and those of members) across the WECC membership. The VGS is modeled in part on the NERC Integration of Variable Generation Task Force (IVGTF) and has a mandate to address operating, planning, and market issues related to variable generation in the Western Interconnection, and to interface and coordinate with the NERC IVGTF. The VGS is in its initial stages of developing work plans. A link to the VGS home page on the WECC Web site is provided below.[23]
- One of the tasks of the VGS Planning Work Group is to evaluate the various data sources available and studies already performed in order to provide guidance on the reliable capacity that is offered by the various kinds of variable renewable generation in the Western Interconnection, focusing particularly on wind generation. This would enable planners to evaluate the amount of other generation and demand-side resources that need to be put in place to ensure adequacy going forward.
- WECC does not, at this time, have a program to evaluate the impacts of gas displacement by large amounts of variable renewable generation on gas markets, gas procurement, and other issues raised for the natural gas system. However, the California Energy Commission (CEC) conducted a study in 2007 that examined the natural gas usage impacts of high penetrations of renewables in California, and the entire Western Interconnection.[24] The report found that with the high penetrations examined, sufficient natural gas usage reductions were predicted and that overall West-wide natural gas price declines could be expected.

  The CEC is conducting additional examinations of the impacts of high renewables on the natural gas system as part of the 2009 Integrated Energy Policy Report proceeding. A forthcoming CEC staff report suggests that a 33 percent renewable scenario on an interconnection-wide basis would reduce the predicted average annual natural gas use in the power generation sector by about 15 percent in the year 2020. This is a comparison to a *Reference Case* with renewable resources built out according to current requirements.[25]

[22] www.wecc.biz/committees/BOD/TEPPC/default.aspx
[23] www.wecc.biz/committees/StandingCommittees/JGC/VGS/default.aspx
[24] "Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Second Addendum." CEC, CEC-200-2007-010-AD2-SD. August 2007.
[25] "Impact of AB32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation." CEC, June 2009.

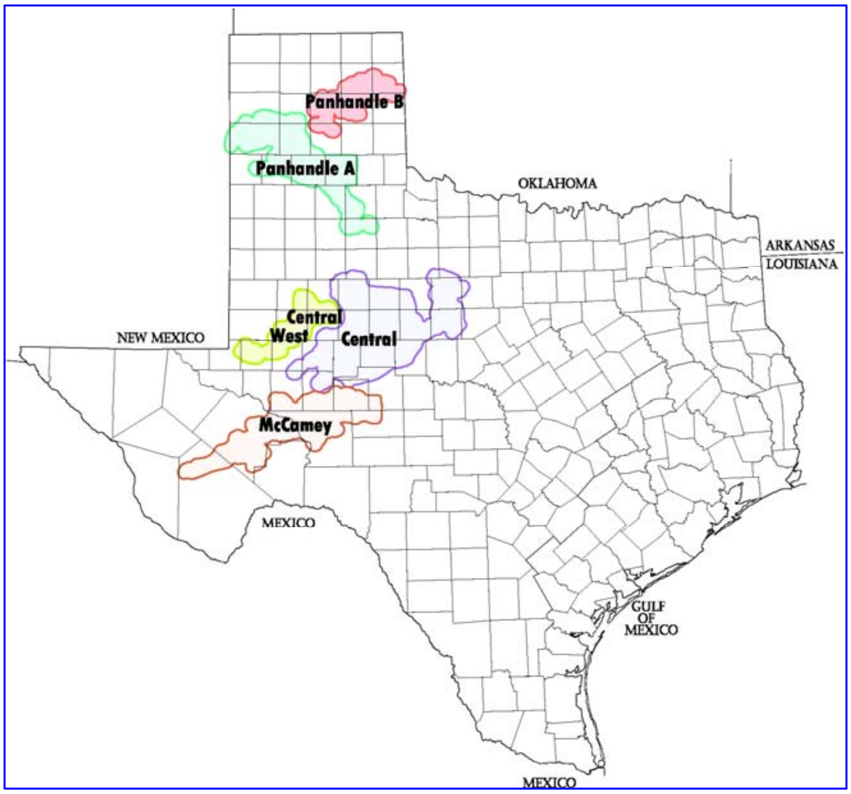
# ERCOT

## Introduction

The *Scenario Case* for the ERCOT Region assesses the impact of adding additional wind energy resources to the *Reference Case* sufficient to provide an additional 15 percent of the energy requirements in the ERCOT Region by 2018, relative to the wind energy resources available in the Region during 2008.[26] These additional wind energy resources bring the total installed wind generation to almost 25 GW. This assessment is intended to comply with Scenario #1 (*Scenario Case*) of the scenario analysis requirement for the 2009 *Long-Term Reliability Assessment* (*Reference Case*).

The *Scenario Case* for ERCOT is based upon the work done in development of the Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study (CTO Study)[27] and the GE Ancillary Services Study,[28] which analyzed the impact of wind generation integration on operations. The CTO Study developed transmission plans for four base scenarios established by the Public Utility Commission of Texas (PUCT). The scenarios took into account the input and concerns of the ERCOT ISO, generation developers, transmission owners, and other stakeholders, including transmission technology options and cost-effectiveness.

**Figure ERCOT-1: Competitive Renewable Energy Zones**




In the Interim Order on Reconsideration in Docket 33672, the PUCT designated five zones as CREZ. These zones are depicted in Figure ERCOT-1. The PUCT also requested that ERCOT develop transmission plans to provide transfer capacity for wind generation as specified in the four scenarios in Table ERCOT-1.

[26] Wind generation in the ERCOT Region provided roughly 15 TWh, or 4.9 percent, of the Region's 312 TWh load in 2008. Assuming a 35 percent capacity factor for wind generation additions, a total installed capacity of roughly 25GW would be required to produce a 15 percent increase in wind energy produced.

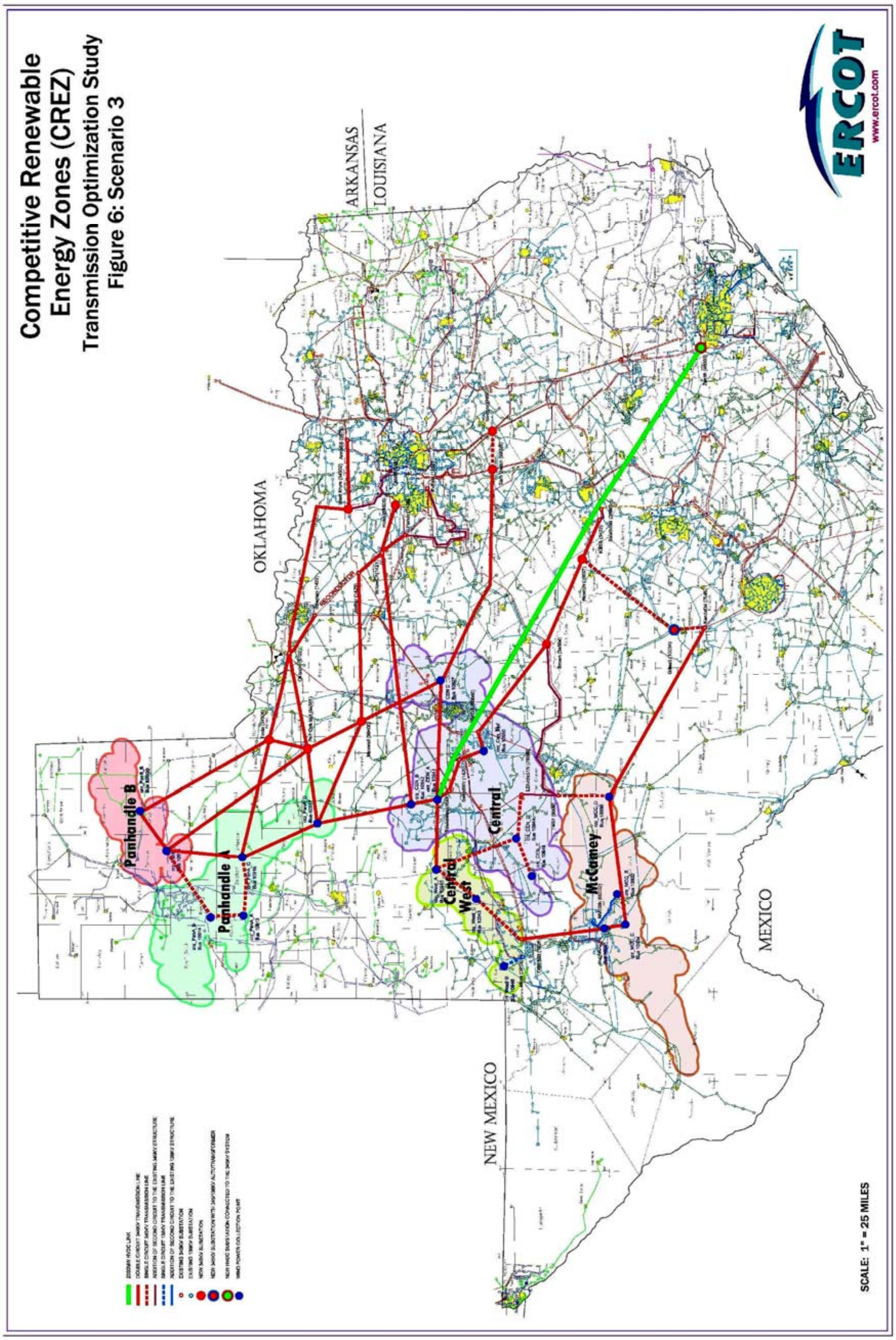
[27] http://www.ercot.com/content/news/presentations/2008/ERCOT_Website_Posting.zip

[28] http://www.ercot.com/content/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_ Services_-_GE_Study.zip

| Table ERCOT- 1: MW Tiers for ERCOT CREZ Transmission Optimization Study | | | | |
|---|---|---|---|---|
| | **Scenario 1 (MW)** | **Scenario 2 (MW)** | **Scenario 3 (MW)** | **Scenario 4 (MW)** |
| **Wind installed as of 4/2/2008** | 6,903 | 6,903 | 6,903 | 6,903 |
| **Incremental CREZ Wind** | | | | |
| **Panhandle A** | 1,422 | 3,191 | 4,960 | 6,660 |
| **Panhandle B** | 1,067 | 2,393 | 3,270 | 0 |
| **McCamey** | 829 | 1,859 | 2,890 | 3,190 |
| **Central** | 1,358 | 3,047 | 4,735 | 5,615 |
| **Central West** | 474 | 1,063 | 1,651 | 2,051 |
| **CREZ Wind Capacity** | 5,150 | 11,553 | 17,956 | 17,516 |
| | | | | |
| **Total Wind Installed** | **12,053** | **18,456** | **24,859** | **24,419** |

Scenario 2 was selected by the PUCT and the construction of the transmission plan necessary to implement this scenario has been ordered by the PUCT. Therefore, this transmission plan is included in the *Long-Term Reliability Assessment Reference Case*. CREZ Scenario 3 provides the basis for this 2009 *Long-Term Reliability Assessment Scenario Case*. The transmission plan developed for Scenario 3 includes several new circuits in the Texas panhandle, and a 2,000MW HVdc circuit from west Texas to the Houston area. These circuits are incremental to the transmission plan included in the *Reference Case*. The combined transmission plan for Scenario 3 (including the CREZ lines that are needed for Scenario 2 as well as the incremental lines for Scenario 3) is depicted in Figure ERCOT-2. The estimated cost of this plan is an incremental $1.45 billion over the plan that is included in the *Reference Case*, plus any incremental interconnection system costs. This plan includes 300 miles of new 345 kV right-of-way and 360 miles of new HVdc right-of-way plus the incremental interconnection facilities.

**Figure ERCOT-2: Scenario 3 Transmission Plan (aka Figure 6 in CREZ study)**



The operational and reliability impacts of this penetration of wind are significant, requiring improved wind forecasting, increased levels of ancillary services and potentially, new types of Ancillary Services, These changes in ancillary services requirements may lead to changes in the installed generation fleet, including the incorporation of different technologies, such as storage solutions and coordinated demand management. While a detailed study of the impact of the Scenario 2 level of wind generation on ancillary services and grid reliability was completed as a part of the CREZ analysis, such a study has not yet been accomplished for the 25 GW level evaluated in this *Scenario Case*. Changes to the current installed fleet of generating units (retirements and additions) would also likely occur at the *Scenario Case* level of installed wind generation, but the current assessment does not address these economic decisions.

### Demand

The weather, economic assumptions, demand forecast, and demand response values used in the *Scenario Case* is the same as in the 2008 *Long-Term Reliability Assessment Reference Case*.

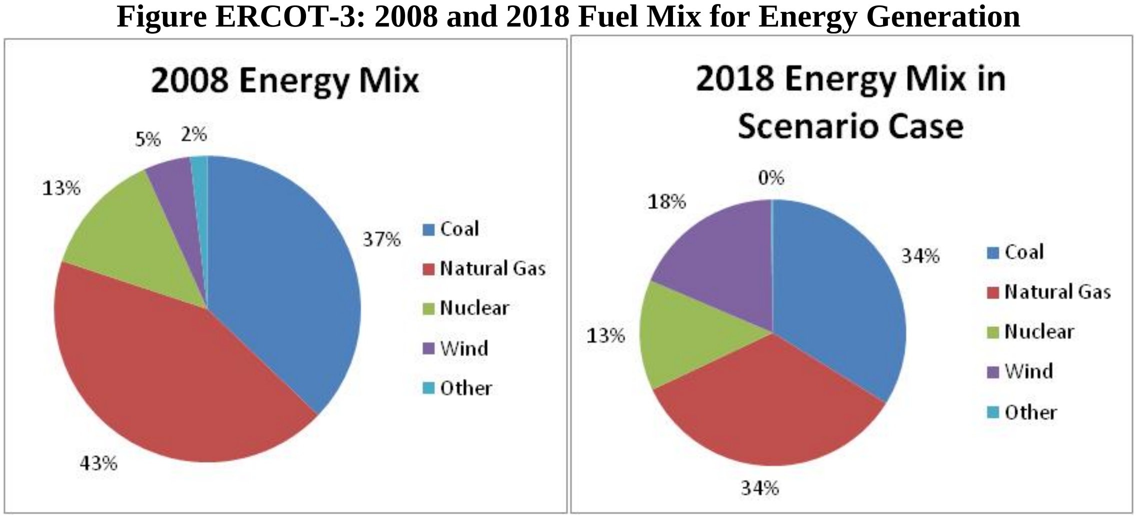
### Generation

In order to meet the requirements, the *Scenario Case* assumes that a total of 24,859 MW of wind generation capacity is online by 2018, which is an additional 14,261 MW of wind generation capacity added to the *Reference Case*.

As in the *Reference Case*, only the Effective Load-Carrying Capability (ELCC) of 8.7 percent of the wind generation nameplate capacity is included in the Existing-Certain amount used for margin calculations. The remaining existing wind capacity amount is included as Existing-Other generation. Consequently, the expected on-peak capacity of these resources range from a current value of 708 MW to 919 MW by 2013 and to 2,163 by 2018.

Figure ERCOT-3 reflects the fuel mix for generation in the Region. In the *Scenario Case*, wind energy represents 18 percent of the total energy generated in 2018, which is a significant increase over the 5 percent of 2008 load produced by renewable generation in 2008.

**Figure ERCOT-3: 2008 and 2018 Fuel Mix for Energy Generation**



In the *Reference Case*, a new power project must have a binding interconnection agreement and air permit before it is included in reserve margin calculations[29]. However, for the *Scenario Case*, the ELCC for the incremental amount of wind generation (above the amount that is included in the *Reference Case*) necessary to meet the intent of the Scenario is included in the reserve margin calculation. Of the incremental 14,261 MW of new wind capacity, 1,241 MW (8.7 percent) contributes to margin calculations.

This assessment does not include the impact of any changes to installed generation capacity as a result of the market conditions resulting from the additional wind generation included in this Scenario. These changes include retirements and/or additions of conventional and/or new generation technology, that might be made by participants in the competitive ERCOT wholesale market.

### Capacity Transactions on Peak

For the *Scenario Case*, no changes are made to the *Reference Case* purchases and sales on peak.

### Transmission

The *Scenario Case* is built from an analysis provided for the CREZ process, specifically for Scenario 3, which included 24,859 MW of total wind generation capacity. The transmission improvements ordered by the PUCT in the CREZ process, necessary to meet CREZ Scenario 2, are already included in the 2009 *Long-Term Reliability Assessment Reference Case*. CREZ Scenario 3 included several new 345 kV rights-of-way in West Texas, as well as a new 2,000 MW HVdc circuit from West Texas to the Houston area. The incremental transmission additions necessary to support the increase from CREZ Scenario 2 to CREZ Scenario 3 are included in this *Long-Term Reliability Assessment Scenario Case* as incremental transmission requirements for the *Long-Term Reliability Assessment Scenario Case*. These incremental requirements include 300 miles of new 345 kV right-of-way and 360 miles of new HVdc[30] right-of-way. The incremental system upgrades include new lines, equipment upgrades, and reactive compensation. Details on the projects can be found in the CREZ Transmission Optimization Study report[31]. The table below summarizes, by voltage class, the number of additional new transmission line miles attributed to the *Scenario Case*.

| Voltage (kV) | Incremental Transmission above *Reference Case* (Miles) |
|---|---|
| 138 | 0 |
| 345 | 300 |
| HVdc | 360 |
| **Total** | **660** |

[29] http://www.ercot.com/content/meetings/tac/keydocs/2007/0330/11._Draft_GATF_Report_to_TAC_-_Revision_2.doc
[30] This HVdc Line would be rated at 2000 MW
[31] The CREZ study can be found at http://www.ercot.com/content/news/presentations/2008/ERCOT_Website_Posting.zip

### Operational Issues

The continued increase in wind generation has the potential to lead to increased operating challenges, even more so in this Scenario. The Renewable Technologies Working Group (RTWG) has been established to coordinate activities related to wind integration in the ERCOT Region. The RTWG has produced a work plan for study and resolution of all identified wind integration issues and is reporting to the PUCT on a quarterly basis.[32]

ERCOT ISO has already implemented several operational changes intended to maintain system reliability with the inclusion of significant wind resources. ERCOT has implemented a centralized wind forecasting system. In addition, ERCOT has updated the ancillary service methodology, which is used to determine the procured quantities of ancillary services, to account for wind uncertainty. These changes allow ERCOT to adjust the amount of Non-Spinning Reserve Service to account for the uncertainty associated with not only load forecasting but wind forecasting as well. The ancillary service methodology change also accounts for increases in installed wind capacity in the Regulation Service. ERCOT is actively developing both a probabilistic operational risk assessment program and wind ramp event forecasting system to further assess the risk associated with high-wind penetration during the operations planning timeframe and allow for timely mitigation of the identified risks through the procurement of appropriate ancillary services. Finally, ERCOT has implemented voltage ride-through requirements for new wind generation and is studying the benefits of the application of these requirements to existing wind generation. All of these processes are needed for *Long-Term Reliability Assessment Reference Case* levels of wind generation and would also provide mechanisms to maintain reliability in with the *Scenario Case* level of wind generation.

The impact of wind generation on ancillary services requirements is a concern for the Region. The level of ancillary services necessary to reliably support approximately 15 GW (relative to a 2014 load level) was evaluated in a study performed by General Electric (GE Ancillary Services Study) for ERCOT in 2006[33]. While the additional level of ancillary services necessary to support the approximate 25 GW presumed in this Scenario was not evaluated, the GE Ancillary Services Study provides valuable insight on ancillary service concerns.

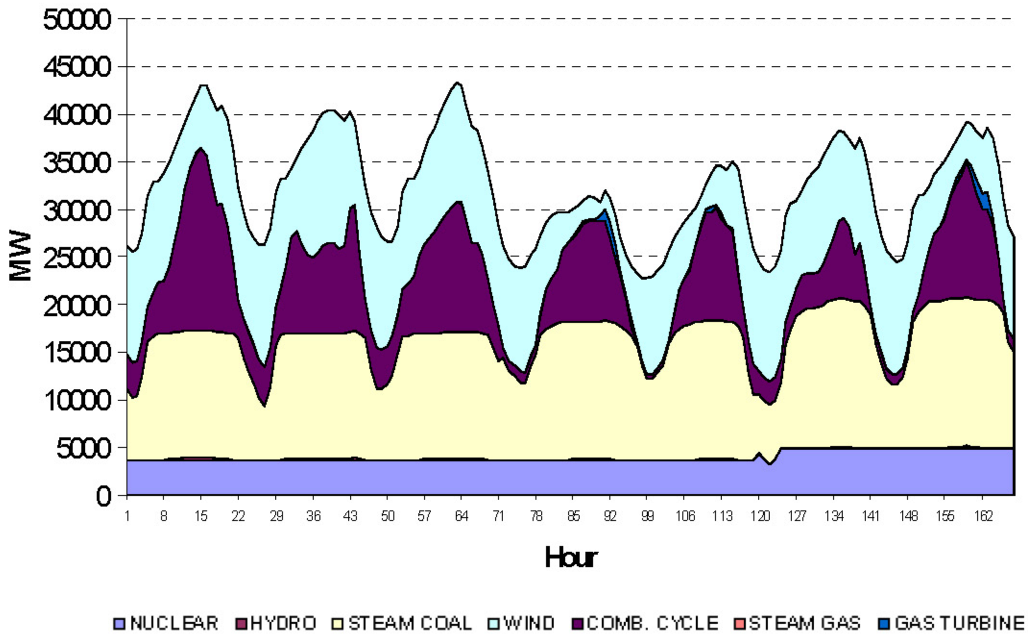
The GE Ancillary Services Study (Figure ERCOT-4) also shows that in the high wind, low load scenario the committed combined cycle capacity is reduced to almost zero in some overnight periods and the coal fired generation shows some deep turn downs to near minimum output in the overnight dispatch. As the wind capacity is increased to 24 GW, it can be assumed this impact would be increased and it may be necessary to curtail wind output during low load periods in order to have sufficient committed generation to serve the following day's peak, given existing generation fleet.

---

[32] http://www.ercot.com/content/meetings/tac/keydocs/2009/0305/09._ERCOT_Report_to_PUCT_-_March_2009_Final_02-26-2009.doc and http://www.ercot.com/content/meetings/tac/keydocs/2009/0305/09._Attachment_A_-_RTWG_Master_Issues_List_Final_02-26-09.xls

[33] http://www.ercot.com/content/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip

**Figure ERCOT-4: Dispatch for Peak Wind Generation Output, 15 GW Wind Generation**




The GE Ancillary Services Study objectives were to determine the level, type, and cost of additional ancillary services that might be required to maintain the reliability of the ERCOT Region for increasing levels of wind generation, including an evaluation of ERCOT's existing process for determining ancillary services procurement requirements and recommendations for any needed improvements to that process. The study was intended to provide information for both the current operations in the ERCOT Region and the policy discussion associated with the CREZ process.

The following are several key conclusions reached from the GE Ancillary Services Study concerning the integration of the wind generation into the system:

- With 15,000 MW of installed wind capacity in ERCOT (against a 2009 load level), the operational issues posed by wind generation would become a significant focus in ERCOT system operations. However, the impacts can be addressed by existing technology and operational attention, without requiring any radical alteration of operations.
- ERCOT's Regulation Procurement Methodology (RPM) can be improved by including wind forecast information and wind capacity growth.
- Inclusion of wind forecasting in operations planning is critical.
- ERCOT's unit commitment may need to be altered to provide ancillary services.
- Variation of wind tends to be anti-correlated, or out of phase, with the daily load curve, but the errors in load and wind forecast are virtually independent. That means that it is improbable for the most severe load and wind forecast errors to occur in the same hour.
- Additional Regulation would be required in relatively small amounts (54 MW up and 48 MW down).
- Certain improvements to the RPM are recommended.

- Energy production from wind tends to be offset primarily by reduction in production from combined-cycle natural gas plants.
- The cost of the additional ancillary services identified in the report would be small relative to the cost savings from the additional wind generation.

The GE Ancillary Services Study also included the results of an economic dispatch simulation for wind generation and the balance of system generation. This revealed the expected reduction of thermal generation commitment due to the increased amount of wind generation, which in turn impacts the amount of units available to provide ancillary services.

Another issue not covered in the GE Ancillary Services Study, but which impacts the reliable operation of the ERCOT System with significantly increased levels of wind generation, is the frequency response of the system. At the wind penetration illustrated in this *Scenario Case*, wind generation that does not provide an inertia-like response may need to be curtailed during low load time periods in order to maintain sufficient system inertia. The RTWG is developing rule changes to allow wind generation to provide governor-like response.

The PUCT-ordered construction of transmission system upgrades as a part of the CREZ includes significant quantities of static and dynamic reactive devices and additional devices are included in the incremental transmission for the *Scenario Case*. The management of these reactive devices to maintain system voltage and margins within acceptable ranges, given the intermittent nature of the system loading, is expected to require additional/ modified operational procedures.

## Reliability Assessment Analysis

In the *Scenario Case*, the reserve margin by 2018 increases somewhat due to the incremental wind generation added in the *Scenario Case* from 6.0 percent to 6.9 percent. In both this *Scenario Case* and the *Reference Case*, ERCOT 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, based on new generation with signed interconnection agreements, existing resources, and the (in the *Scenario Case*) incremental new wind generation added for the *Scenario Case*.

This assessment did not evaluate the changes that may occur in the installed fleet of generation in economic response to the additional wind generation. No evaluation of changes in the target reserve margin due to the increase in the level of wind generation included in this *Scenario Case* (with any resulting changes to the installed quantities and operating profiles of thermal generation) has been performed.

Only 8.7 percent of existing wind generation nameplate capacity is counted on for Existing-Certain generation, based on an analysis of the ELCC of wind generation in the Region[34]. The remaining existing wind capacity amount is included in the Existing-Other generation amount. Future loss of load probability studies may investigate the potential of changing the ELCC for wind generation as more wind generation is added in the Region. Theoretically, the ELCC for wind in the ERCOT Region would change from 8.7 percent if it was calculated based on the

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

aggregate of all the wind generation included in the *Scenario Case* (due to increased geographic diversity), but this calculation was not performed for this *Scenario Case* assessment since it would be dependent on the geographic distribution of the incremental generation.

Since the ELCC of the additional wind resources were assumed for the purposes of this *Scenario Case* to be additive to the resources in the *Reference Case*, the Region is assumed to have additional reserves in the *Scenario Case* to meet above-normal demands.

The deliverability of the resources included in the *Reference Case* is included in the *Long-Term Reliability Assessment*. The additional transmission included in this *Scenario Case* should provide the ability for the capacity value of the incremental resources to serve system load without detracting from the deliverability of the resources included in the *Reference Case*.

Numerous operational issues would need to be resolved to maintain system reliability at the level of wind penetration assumed in this *Scenario Case*. These issues have already been covered in the Operational Issues section of this assessment.

Since conventional generation remained unchanged for this scenario, any potential fuel supply vulnerability during peak periods is not significantly changed from the *Long-Term Reliability Assessment Reference Case*.

### Region Description

*ERCOT is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. ERCOT is a summer-peaking Region responsible for about 85 percent of the electric load in Texas with an all-time peak demand of 62,339 megawatts in 2006. The Texas Regional Entity (TRE), a functionally independent division of ERCOT Inc., performs the Regional entity functions described in the Energy Policy Act of 2005 for the ERCOT Region. There are 219 Registered Entities, with 342 functions (as of 6/22/2009), operating within the ERCOT Region. Within the ERCOT Region, the ERCOT ISO is registered as the BA, IA, PA, RC, RP, TOP and TSP. Additional information is available on the ERCOT web site*[35].

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

# FRCC

## Introduction

Nationally, the definition of renewable resources varies from state to state. While almost all states treat solar and wind as renewable resources, many states differ on the applicability of other forms of renewable resources such as municipal solid waste facilities and some types of hydroelectric and cogeneration facilities. The State of Florida has defined the term “Renewable Energy” in Florida Statutes 366.91 as “electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power. The term includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations.” Further the term “Biomass” is defined as “combustible residues or gases from forest products manufacturing, agricultural and orchard crops, waste products from livestock and poultry operations and food processing, urban wood waste, municipal solid waste, municipal liquid waste treatment operations, and landfill gas.”

The scenario assessment performed by the FRCC compared the 2017 Load and Resource Plan submitted in 2008 to a modified plan based on each FRCC entity providing a potential renewable generation plan in order to achieve an additional 15 percent Net Energy for Load (NEL) from renewable resources. Due to climate and geography, Florida has very limited levels of conventional renewable resources such as hydro and wind energy. Florida’s renewable electric resources would largely be derived from biomass, landfill gas, bio-fuels and Solar Photovoltaic (PV) being the dominating renewable resource in the *Scenario Case*. A significant assumption driving the development of the *Scenario Case* was indentifying the location for the additional renewable generation resources. The majority of the potentially feasible locations in Florida for renewable resources are environmentally sensitive. Due to the restricted availability of locations to accommodate renewable generation facilities within the FRCC Region such as a Solar PV field, renewable generation facilities were assumed to be sited in rural undeveloped areas of the state with little or no transmission facilities available resulting in the need to construct 31 miles of new transmission. Approximately 178 miles of existing transmission lines would need to be upgraded.

The *Scenario Case* involved a qualitative determination of required renewable resources in order to achieve a 15 percent of the total NEL being served by renewable resources. Three percent reduction of the total NEL is expected from Energy Efficiency goals. The remaining 12 percent is directly associated with renewable resources. A qualitative evaluation was performed to ensure deliverability of the potential renewable resources for the 2017 study year. Since specific locations for the potential renewable resources could not be identified, these resources were modeled as connected to the nearest transmission facility for the purposes of this *Scenario Case*. Therefore, the incremental transmission enhancements identified as part of the *Scenario Case* do not include any potential facilities required to interconnect these renewable resources. The qualitative evaluation did not identify any reliability impacts associated with the *Scenario Case*. However, it is anticipated there would be a need to develop operating guides in order to mitigate potential operating issues that may develop with the potential penetration of solar resources as modeled in the *Scenario Case*.

### Demand

The demand forecast for year 2017 in the *Scenario Case* is 0.5 percent lower than the *Reference Case* attributed to Energy Efficiency. These Energy Efficiency programs are implemented by entities throughout the FRCC Region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliance (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates, and high efficiency lighting rebates.

### Generation

The data shown in the tables below was collected from individual entities throughout the FRCC Region and compiled to reflect Regional totals. Due to Florida's climate and geography, there are limited levels of conventional renewable resources such as hydro and wind energy. Therefore, Florida entities believe that future renewable electric resources would be derived mostly from biomass, landfill gas, bio-fuels, and solar. The majority of the renewable resource energy for the *Scenario Case* is expected to come from Solar PV. The table below summarizes the incremental resource changes, applied to the *Reference Case*, over the ten-year planning horizon used to develop the *Scenario Case*.

**Table FRCC-1: Incremental Resource Changes in *Reference Case (MW)***

| | | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Variable | Name Plate | 0 | 220 | 440 | 1,920 | 3,689 | 5,458 | 7,229 | 9,892 | 15,369 | 17,277 |
| | Capacity on-peak | 0 | 55 | 110 | 565 | 1,042 | 1,519 | 1,996 | 2,473 | 3,650 | 4,132 |
| Biomass | Name Plate | 0 | 24 | 24 | 68 | 175 | 411 | 631 | 1,398 | 1,622 | 1,777 |
| | Capacity on-peak | 0 | 24 | 24 | 68 | 140 | 386 | 606 | 1,373 | 1,597 | 1,752 |
| Conventional | Name Plate | 0 | -3 | -3 | -394 | -880 | -1,438 | -2,154 | -2,812 | -3,972 | -4,490 |
| | Capacity on-peak | 0 | -3 | -3 | -394 | -880 | -1,438 | -2,154 | -2812 | -3,972 | -4,490 |

The table below compares the *Scenario Case* and *Reference Case* generation mix for each seasonal summer peak over the ten-year horizon.

**Table FRCC-2: Fuel-mix comparison for Reference and *Scenario Cases***
**Projected Available Generation Mix (MW)**

| | | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Nuclear | Reference | 3,896 | 3,896 | 3,933 | 3,933 | 4,372 | 4,476 | 4,476 | 4,476 | 5,649 | 6,823 |
| | Scenario | 3,896 | 3,896 | 3,933 | 3,933 | 4,372 | 4,476 | 4,476 | 4,476 | 5,649 | 6,823 |
| | Change | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | Reference | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 |
| | Scenario | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 |
| | Change | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Coal | Reference | 8,614 | 8,469 | 8,465 | 8,467 | 8,474 | 8,496 | 9,326 | 9,346 | 9,346 | 9,346 |
| | Scenario | 8,614 | 8,466 | 8,462 | 8,474 | 8,481 | 8,503 | 9,333 | 9,353 | 9,353 | 9,353 |
| | Change | 0 | -3 | -3 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Oil | Reference | 10,939 | 10,346 | 10,356 | 10,366 | 10,366 | 10,237 | 10,237 | 10,237 | 10,178 | 10,178 |
| | Scenario | 10,939 | 10,346 | 10,356 | 10,366 | 10,366 | 10,237 | 10,237 | 10,237 | 10,178 | 10,178 |
| | Change | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | Reference | 26,413 | 29,236 | 31,039 | 32,860 | 33,090 | 34,807 | 35,243 | 35,489 | 38,072 | 38,807 |
| | Scenario | 26,413 | 29,236 | 31,039 | 32,460 | 32,204 | 33,363 | 33,083 | 32,671 | 34,094 | 34,311 |
| | Change | 0 | 0 | 0 | -400 | -886 | -1,444 | -2,160 | -2,818 | -3,978 | -4,496 |
| Solar | Reference | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Scenario | 0 | 55 | 110 | 565 | 1,042 | 1,519 | 1,996 | 2,473 | 3,650 | 4,132 |
| | Change | 0 | 55 | 110 | 565 | 1,042 | 1,519 | 1,996 | 2,473 | 3,650 | 4,132 |
| Other | Reference | 1,188 | 1,197 | 1,166 | 1,368 | 1,435 | 1,435 | 1,379 | 1,379 | 1,378 | 1,378 |
| | Scenario | 1,188 | 1,219 | 1,199 | 1,432 | 1,571 | 1,819 | 2,018 | 2,785 | 3,009 | 3,164 |
| | Change | 0 | 22 | 33 | 64 | 136 | 384 | 639 | 1,406 | 1,631 | 1,786 |

The charts below show the expected energy mix for 2017 as well as renewable energy by type of renewable.

**Figure FRCC-1: Energy-Mix 2017**

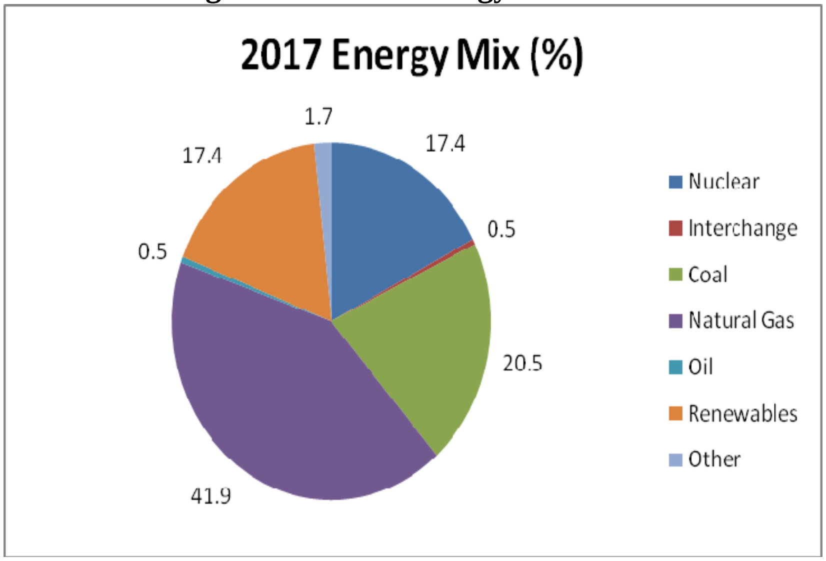
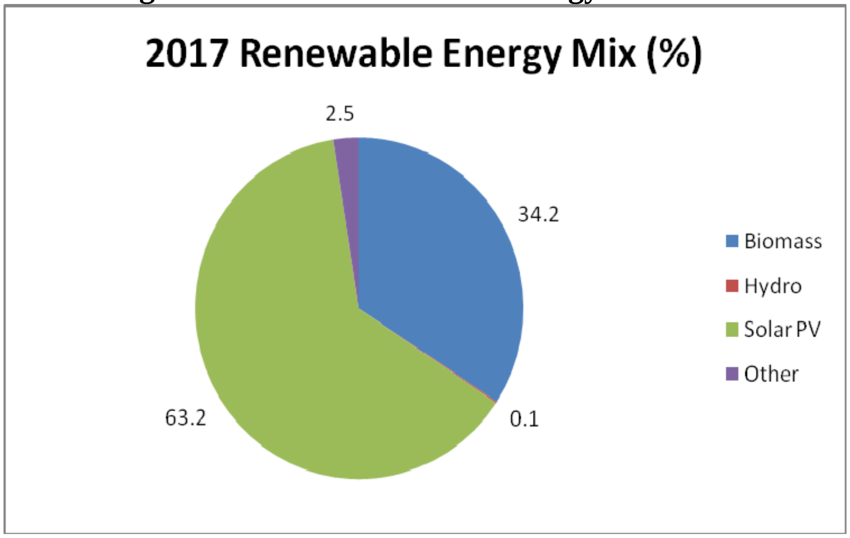



**Figure FRCC-2: Renewable Energy-Mix 2017**




FRCC entities have an "obligation to serve" and this obligation is reflected within each entity's 10-Year Site Plan filed annually with the Florida Public Service Commission. Therefore, FRCC entities consider all Planned and Proposed capacity resources as "Planned" and included in Reserve Margin calculations. Currently, the State Legislature has not acted on proposed legislation leaving the State of Florida without a Renewable Portfolio Standard.

## Purchases and Sales

There are no differences in purchases and sales when comparing the *Reference Case* with the *Scenario Case*. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts (as available) in place between SERC and FRCC members.

## Transmission

For the *Scenario Case*, individual transmission owners may need to construct approximately 14 miles of additional 230 kV transmission lines and network upgrades of approximately 132 miles of 230 kV transmission lines during the 2008—2017 planning horizon. In addition, one 230/138 kV transformer may need to be upgraded.

The table below summarizes, by voltage class, the number of additional new transmission line miles attributed to the *Scenario Case* as well as the number of transmission line miles that may require upgrades in order to integrate these renewable resources. Additional transmission facilities may be required in order to interconnect the proposed renewable resources. The amount and type of interconnection facilities that may be required can be extensive depending on siting locations relative to the existing transmission network. In addition, any changes to the assumed siting locations of these renewable resources used to assess the *Scenario Case*, can also have an impact on the amount and type of required facilities to integrate these resources.

| Voltage (kV) | Transmission Lines (Miles) | |
|---|---|---|
| | Upgrade | New |
| 69 | 10 | 5 |
| 115 | 7 | 0 |
| 138 | 28 | 13 |
| 230 | 132 | 14 |
| **Total** | **178** | **31** |

## Operational Issues

Additional operating guides are expected to be developed in order to mitigate potential operating issues that may develop with the potential penetration of solar resources as modeled in the *Scenario Case*. For example, a Solar PV installation does not involve a rotating mass and therefore does not have inertia. Therefore, operating Solar PV systems have the potential for substantial ramps during partially cloudy days typical of the Florida weather patterns. Solar PV systems can experience variations in output of +/- 50 percent in a 30 to 90 second time frame and +/- 70 percent in a five to ten minute time frame.[36] These type of ramps in the output of Solar PV plants can be experienced many times in a single day during certain weather conditions.

Operating guides would likely include requirements to address the challenges of sudden changes in ramp rates throughout the day. These guides may need to limit the amount of Solar PV generation that can be online in a given area, based on the projected demand, to account for reactive requirements as well as frequency response requirements. Presently, high penetration levels of Solar PV within the FRCC Region are not expected to occur until more experience is gained in the operating arena to ensure the power system remains reliable.

[36] NERC Special Report: Accommodating High Levels of Variable Generation (Page 27).

## Reliability Assessment Analysis

The average projected Reserve Margin throughout the ten-year horizon is 19.5 percent for the *Reference Case* and 20.2 percent for the *Scenario Case*. The Reserve Margin criteria is 15 percent (20 percent for Investor Owned Utilities) as required by the Florida Public Service Commission (FPSC).

By 2017 the amount of internal generation resources within the FRCC Region that are included in the Reserve Margin calculation are 1,428 MW higher in the *Scenario Case* as compared to the *Reference Case*. The amount of resources external to the FRCC Region did not change between the two cases. The only changes identified regarding resource adequacy are reflected in the slightly higher Reserve Margin identified to achieve the 15 percent renewable energy target for the *Scenario Case*.

No changes are identified between the *Reference Case* and the *Scenario Case* with regards to unit retirements.

The deliverability of potential renewable resources included in the *Scenario Case* can be ensured with the addition of new transmission facilities and upgrades to existing transmission facilities as identified in the Transmission section of this assessment.

The *Scenario Case* for the FRCC Region assumes a substantial increase in Solar PV penetration. Solar PV technology converts the electromagnetic energy in sunlight directly into direct current. In order to interconnect a Solar PV plant with the power system, power electronic inverters are needed to convert the direct current output at the terminals of the Solar PV panel.[37] Prior to the implementation of a substantial increase in Solar PV extensive frequency response studies would probably be necessary to determine appropriate power system support requirements. These studies would require Solar PV ramp rate data obtained from real-time operations over the course of several years. In addition, it is expected that reactive support requirement studies would be necessary depending on the size of the Solar PV installation as well as the location. The results of these detailed studies may reveal limitations regarding the amount of Solar PV penetration that can be reliably integrated throughout the FRCC Region. At this time, the FRCC Region does not anticipate any specific changes to the existing wholesale market in order to implement the *Scenario Case*. However, operational procedures may be required when certain levels of renewable energy become available for dispatch.

The FRCC Region has not identified any specific fuel supply vulnerability between the *Reference Case* and the *Scenario Case*. However, the fuel mix for the *Scenario Case* shows an improved fuel diversity that should reduce the risk of potential fuel supply vulnerability concerns.

[37] NERC Special Report: Accommodating High Levels of Variable Generation (Page 27).

## Region Description

*FRCC's membership includes 26 Regional Entity Division members and 25 Member Services Division members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. The Region has been divided into 11 Balancing Authorities. As part of the transition to the ERO, FRCC has registered 76 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The Region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC website (https://www.frcc.com/default.aspx).*

# MRO

## Introduction

Two *Reference Case*s were used in this scenario assessment. One *Reference Case* was the MRO 2008 *Long-Term Reliability Assessment* data. The other case was the 2008 Joint Coordinated System Plan (JCSP) study.[38]

The 2008 MRO *Long-Term Reliability Assessment* dataset contains projected changes to the load, generation and transmission assets within the MRO footprint across a ten-year period starting in 2008 and extending through 2017. This dataset serves as "*Reference Case 1.*"

Two scenarios associated with this *Reference Case* are assessed. The key difference between *Reference Case 1* and the associated *Scenario Cases* is the projected wind generation nameplate capacity expected to be in service by the year 2017. The first scenario assumes an addition of 11,600 MW by 2017 that serves 15 percent of 2017 energy in the MRO-US footprint (above and beyond the 5.2 percent that would be served with the Existing wind generation of 4,000 MW). The total wind generation nameplate capacity is 15,600 MW (equivalent to 20.2 percent of 2017 energy) in this scenario. The second scenario assumes an additional 15 percent of 2017 energy is served by wind generation beyond the 26.5 percent of energy assumed to be served by the 20,500 MW of wind generation identified in the 2008 *Long-Term Reliability Assessment*. A total of 32,100 MW would be required in this scenario, which is equivalent to 41.5 percent of 2017 energy in the MRO-US footprint. Sensitivities of 5 percent load reduction through Energy Efficiency were assessed for each of the two scenarios. More discussions on this set of base and *Scenario Cases* can be found under Generation section.

The second *Reference Case*, "*Reference Case 2,*" was the 2008 JCSP study. This case included the amount of wind generation required by the states Renewable Portfolio Standards (RPS) mandates that were in place when such assumptions were made. On average, about 5 percent of the energy use in the JCSP footprint (United States Eastern Interconnection excluding Florida) was assumed to come from wind in this case. The wind generation sited within the MRO-US footprint adds up to 16 percent (12,169 MW) of the MRO-US energy needs in 2024 in this case.

The "*Scenario Case 2*" associated with *Reference Case 2* represents the JCSP 20 percent Wind Case. This case represents a scenario where 20 percent of the 2024 energy in the joint study footprint comes from wind. The joint study footprint includes all Eastern Interconnection load in the United States except Florida. In this scenario, a large amount of wind was sited in the western part of the Eastern Interconnection including MRO-US and SPP footprints where there are superior terrestrial wind resources. The wind generation sited within the MRO-US footprint is equivalent to 97 percent (70,000 MW nameplate) of the energy needs in MRO-US footprint in 2024. This indicates that the MRO-US footprint also supplies a large amount of wind energy to the eastern part of the Eastern Interconnection. This wind siting assumption creates a west to east power flow bias through the Eastern Interconnection.

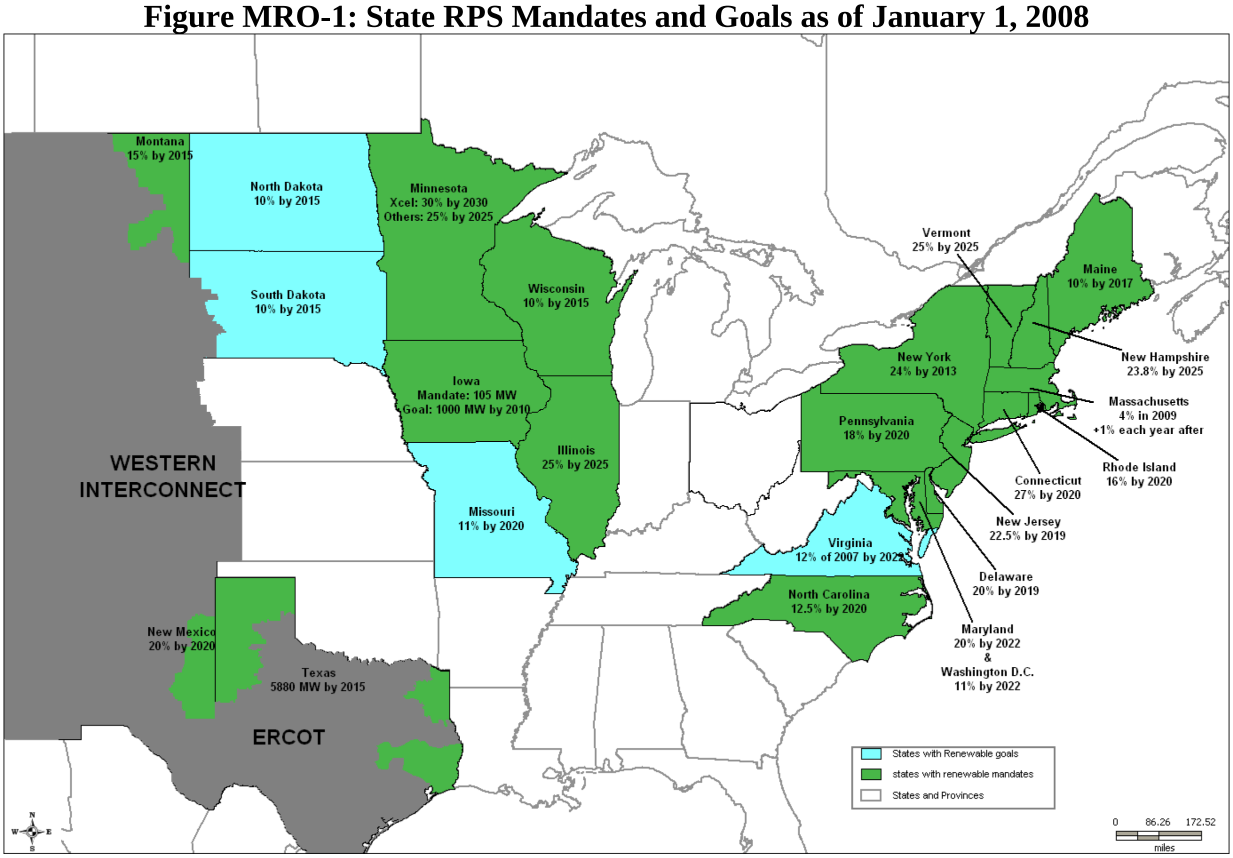
[38] http://jcspstudy.org JCSP study was initiated by a number of Regional organizations in the Eastern Interconnection including the Midwest ISO, PJM, TVA, SPP and Entergy. Stakeholders of these Regional organizations and other interested parties also participated in this study.

## Overview of the Study and Reliability Impacts of the *Scenario Case*

This assessment uses the JCSP study for transmission-related discussions. The JCSP study investigated transmission overlays across the joint study footprint of Eastern Interconnection in the Unites States except Florida for two wind scenarios—Reference scenario and 20 percent Wind scenario. The generation forecast and siting were performed, which provide necessary generator assumptions for the transmission overlay studies. The JCSP study involves major transmission operators in the Eastern Interconnection. The study participants include Midwest ISO, SPP, PJM, TVA, MAPP, several key members of SERC, stakeholders of these Regional organizations and other interested parties.

The reference scenario assumes the existing RPS laws and policies governing generation resource choices remain in place. The wind generation assumed in this scenario is based on existing state RPS mandates on January 1, 2008, which translates to an average of 5 percent wind energy development across the joint study footprint. The siting of wind generation is "local" — close to load centers within each state that has an RPS mandate. Although there are multiple renewable resource types that satisfy RPS standards throughout the states, the JCSP assumes that incremental mandate needs would be met solely with wind resources. States with goals, or proposed targets, are not included in this wind assignment. The RPS mandates and goals used in the JCSP study are detailed in Figure MRO-1. Under the Reference scenario there is about 60,000 MW of new wind capacity by 2024 along with about 75,600 MW of new base load steam generation.

**Figure MRO-1: State RPS Mandates and Goals as of January 1, 2008**



The 20 percent Wind Scenario assumes the joint study footprint would meet 20 percent of its energy by 2024 using wind generation. In this scenario, large amounts of wind is assumed to be located in those areas with highest quality wind resources, largely in the MRO-US and SPP footprints in the western part of the Eastern Interconnection. Under the 20 percent Wind scenario there is about 229,000 MW of new wind capacity by 2024 along with about 36,000 MW of new base load steam generation.

The wind penetration levels in the *Scenario Cases* discussed above range from 20 to 97 percent (in terms of energy) in the MRO-US footprint, which are much higher than the existing 5.2 percent (as of June 2008). Particularly, in *Scenario Case 2* the amount of wind sited within the MRO-US footprint is equivalent to 97 percent (70,000 MW nameplate) of the energy needs in the MRO-US footprint in 2024. This indicates that if the MRO-US footprint also supplies a large amount of wind to the eastern part of the Eastern Interconnection, above and beyond its own states RPS mandates, the wind penetration level within MRO footprint would become extremely high.

Wind penetration at these levels would create increasingly greater operational challenges that may jeopardize the reliability of the bulk power system. It also creates challenges for designing and constructing the transmission infrastructure needed to accommodate the increased flows through the Eastern Interconnection. In this assessment, emphasis is placed on the transmission and operational issues associated with high-wind penetration levels.

The JCSP study work to-date provides “order of magnitude” type information related to the conceptual transmission overlays. The study offers one approach to investigate transmission overlay across a large area and one design idea. However, the adequacy of the resulted overlays or the necessity of any overlay elements has not been thoroughly investigated. The reliability studies were not performed for these overlays. The indicative designs of these overlays relate to the specific generation and other assumptions used in the study, e.g., generation siting philosophy and methodology, the assumption of large amount of wind sited in the MRO-US and SPP footprints, etc. The outlook of the conceptual transmission overlay may change a great deal if some of these assumptions are changed. Therefore, the transmission facilities cited in this assessment based on the JCSP study should not be taken out of the proper context.

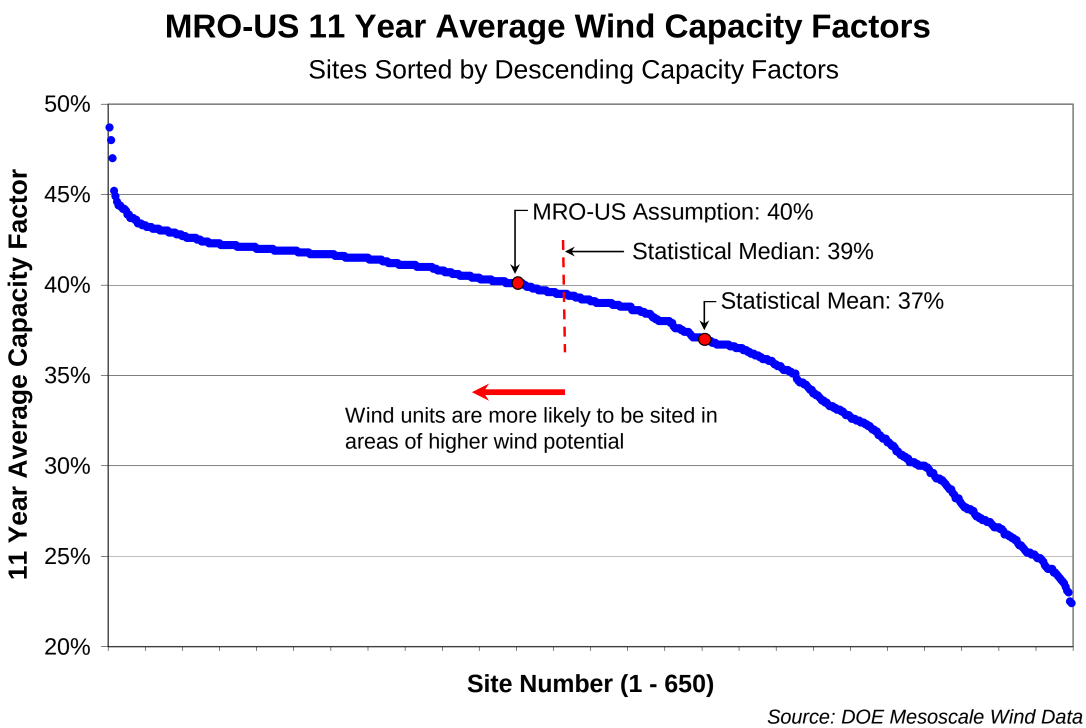
**Significant Assumptions**

Figure MRO-2 shows wind plant capacity factors estimated from the wind data for 650 sites within the MRO-US footprint over 11 years. For each of the 650 sites, capacity factors were obtained by converting wind speeds at 80 meter- and 100 meter-altitudes to a theoretical wind turbine output. Unit types were chosen to optimize output given that site’s wind characteristics. Capacity factors for each site were then arranged in descending order for graphical purposes to create Figure 2. Capacity factors for the MRO-US range from 22 to 45 percent, with 37 percent being the statistical mean. Since sites were dispersed fairly evenly throughout the MRO-US, it can be assumed that 37 percent is a valid average for unit output across the entire footprint.

However, because wind units are more likely to be sited in areas of higher wind levels, a capacity factor slightly higher than the statistical mean is assumed for the purposes of this assessment. The *Reference Case* and *Scenario Case 1* use a 40 percent capacity factor for the

MRO. In *Scenario Case 2*, which references the JCSP, a 45 percent capacity factor was assumed for future wind units sited within the larger MRO and MISO-West areas.

**Figure MRO-2: Capacity Factors Estimated for Sites within the MRO-US Footprint**




The majority of high quality wind is located in the Great Plains. These high capacity factors make for an increased potential that wind units beyond what is required to meet local RPS mandates or goals would be sited within the MRO footprint. *Scenario Case 2* assumes approximately 70,000 MW of wind generation is sited within the MRO-US footprint, while only about 17,000 MW is required for 20 percent of the MRO-US energy needs.

Based on the historical data available in the Region, it was assumed 20 percent of the nameplate capacity would be available on peak.

## Demand

The MRO did not send a new data request to its Load Serving Entities for the Scenario Assessment. Therefore the weather, economic assumptions, demand, and demand response values used in the 2008 *Long-Term Reliability Assessment (Reference Case)* have been used for this *Scenario Case*. Sensitivity with or without a 5 percent Energy Efficiency was analyzed in the total required wind generation calculations as discussed in the Generation section.

## Generation

**Wind Generation in the 2008 *Long-Term Reliability Assessment* (*Reference Case 1*)**
In the 2008 *Long-Term Reliability Assessment*, generation was categorized as Existing, Planned, or Proposed. Approximately 4,000 MW of wind generation nameplate capacity was expected to be in service and available for summer 2008. This 4,000 MW of wind generation is categorized as Existing generation. The 2008 *Long-Term Reliability Assessment* also identified about 1,000 MW of Planned wind generation by 2017. 100 percent of Existing and Planned wind generation is included in the 2008 *Long-Term Reliability Assessment*. However, only a portion of Proposed wind generation was included. The Proposed wind generation for each year (attained from the Midwest ISO interconnection queue) was multiplied by a confidence factor. Confidence factors varied and were higher in the earlier years since these resources were assumed to be more likely to be built.

The total Proposed wind generation in the interconnection queue per year, the confidence factors applied per year, and the resulting Adjusted Proposed wind generation per year are shown in Table MRO-1.

**Table MRO-1: Fuel-mix comparison for Reference and *Scenario Cases***

| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Confidence Factor | 50 % | 45 % | 40 % | 35 % | 35 % | 35 % | 20 % | 20 % | 20 % | 20 % |
| Total Wind Generation in Queue per Year (MW) | 2,336 | 8,449 | 12,490 | 5,636 | 7,701 | 2,150 | 350 | 50 | 500 | 50 |
| Adjusted Proposed Nameplate (MW) | 1,170 | 3,790 | 4,965 | 1,940 | 2,700 | 745 | 70 | 10 | 100 | 10 |

The Adjusted Proposed wind generation amounts to 15,500 MW by 2017 (compared to a total Proposed value of 39,700 MW). The total nameplate capacity of wind generation, including Existing (4,000 MW), Planned (1,000 MW), and Adjusted Proposed (after applying yearly confidence factors) is 20,500 MW. Because the Scenario Assessment is based on annual energy, the expected annual energy from 20,500 MW of nameplate capacity is needed. Assuming a 40 percent capacity factor, the expected contribution from 20,500 MW of nameplate wind in 2017 would be about 71,800 GWh, or about 26.5 percent of the 271,200 GWh within the MRO-US footprint.

**Scenario Assessment 1: 15 percent Energy Served in Addition to Existing 4000 MW**
The Scenario Assessment requests that 15 percent of the 2017 Regional energy (above and beyond the 5.2 percent that would be served with the Existing wind generation of 4,000 MW) is to be served by wind generation. A total of about 15,600 MW of wind generation nameplate capacity would be required to achieve this, assuming zero percent load reduction through Energy Efficiency. The rate at which this amount of wind generation would be ramped in over 10 years is assumed to be the same as what was assumed above in the *Long-Term Reliability Assessment*.

**Scenario Assessment 1 with 5 percent Load Reduction through Energy Efficiency**

It is unknown at this time how much load reduction might be attained by 2017 through Energy Efficiency programs and products. However, assuming that 5 percent load reduction is realized by 2017, the total nameplate MW of wind generation required to serve 15 percent energy above and beyond the Existing 4,000 MW of wind generation would be 15,000 MW.

**Scenario Assessment 2: 15 percent Energy Served in Addition to *Long-Term Reliability Assessment* 20,600 MW**

If an additional 15 percent of 2017 energy is served by wind generation beyond the 26.5 percent of energy assumed to be served by the 20,500 MW of wind generation identified in the 2008 *Long-Term Reliability Assessment*, a total of 32,100 MW would be required. This would constitute about 41.5 percent of the energy in the MRO -US footprint. This scenario would require significant transmission reinforcements to deliver this magnitude of energy. Transmission reinforcements are discussed in detail in the JCSP report and are included in the Transmission section of this assessment.

**Scenario Assessment 2 with 5 percent Load Reduction through Energy Efficiency:**

Assuming that 5 percent load reduction is attained by 2017 through Energy Efficiency programs and products, the total nameplate capacity of wind generation required to serve 15 percent energy above and beyond the Existing 20,500 MW of wind generation identified in the 2008 *Long-Term Reliability Assessment* would be 31,500 MW. This would constitute about 42.9 percent of the energy in the MRO-US footprint.

**Table MRO-2: Wind Generation Nameplate Capacity Comparison between *Long-Term Reliability Assessment* Base Case and Associated *Scenario Cases*.**

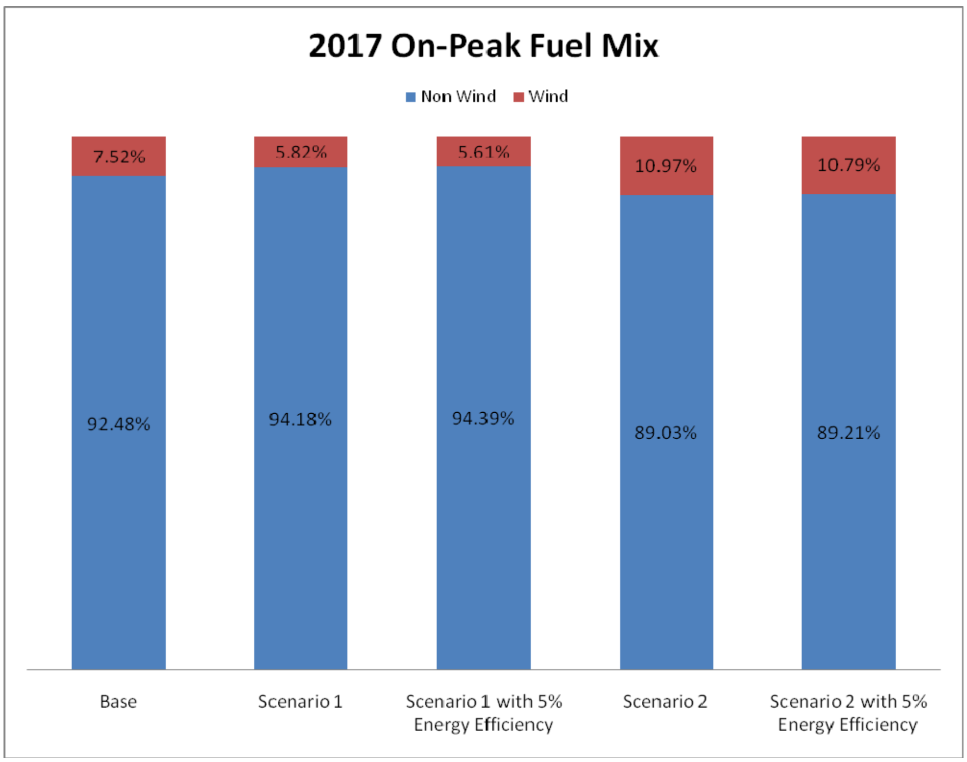
| | Nameplate MW of Wind Generation | 2017 Energy Served ( percent) |
|---|---|---|
| 2008 LTRA: *Reference Case 1* | 20,600 MW | 26.6 percent |
| Scenario 1: 15 percent Energy Served Beyond Existing 4,000 MW of Wind Identified for 2008 | 15,600 MW | 20.2 percent |
| Scenario 1 With 2017 Energy Reduced by 5 percent Due to Energy Efficiency | 15,000 MW | 20.4 percent |
| Scenario 2: 15 percent Energy Served Beyond Existing/Planned/Proposed 20,600 MW of Wind in LTRA for 2017 | 32,100 MW | 41.5 percent |
| Scenario 2 With 2017 Energy Reduced by 5 percent Due to Energy Efficiency | 31,500 MW | 42.9 percent |

### Generation Mix

The generation mix between the 2017 *Reference Case* 1 and the 2017 Scenarios are compared in Figure MRO-3. The comparison is between the wind generation capacity and the conventional (non-wind) generation capacity within the Region. Since the non-wind generation is assumed to be identical to what was identified in the 2008 *Long-Term Reliability Assessment*, it is categorized as one group.

Wind generation on a 100 percent nameplate basis cannot be compared to conventional generation that is dispatchable. Since the wind capability assumed to be available at peak within the MRO Region is 20 percent, this value is used to compare wind generation to conventional generation for fuel mix purposes.

**Figure MRO-3: Wind vs. Non-Wind Generation Fuel Mix**




### Capacity Transactions on Peak

No Regional data request that assessed how capacity transactions would be affected when applying the scenario assessment criteria was conducted. Therefore, this assessment uses the *Reference Case 2* and *Scenario Case 2*, i.e., the JCSP study Reference scenario and 20 percent wind scenario for transaction-related discussions and comparison. The discussion on the *Joint Coordinated System* Plan section of this report shows the megawatt power flows between interfaces during the time of peak load for the JCSP footprint with inclusion of each respective conceptual overlay.

### Transmission

The *Long-Term Reliability Assessment Reference Case* projected transmission additions do not necessarily support the projected wind additions quoted in the *Long-Term Reliability Assessment* (20,600MW), because the *Long-Term Reliability Assessment* includes Adjusted Proposed generation, which is not necessarily assumed in transmission development discussed in the *Long-Term Reliability Assessment*. Therefore the *Reference Case 1* and *Scenario Case 1* are not used for transmission discussions.

This assessment uses the *Reference Case 2* and *Scenario Case 2*, i.e., the JCSP study Reference scenario and 20 percent Wind scenario for transmission-related discussions and comparison.

Appendix A details the lines and transformers that establish the JCSP Reference and 20 percent wind *Scenario Cases* for 2024. Note that a line's full length was included in Table A.1 if it either sources or sinks in the MRO-US Region. Table A.1 compares the total transmission line mileages by voltage categories for *Reference Case 2* and *Scenario Case*

Most of the transmission additions listed in the *Long-Term Reliability Assessment* was included in the base starting points for additional transmission overlay development in the JCSP reference and 20 percent wind *Scenario Cases*. The JCSP conceptual transmission overlays listed in Appendix A and Table A.1 represent tremendous incremental additions to the transmission reinforcements reported in the *Long-Term Reliability Assessment*.

### Operational Issues

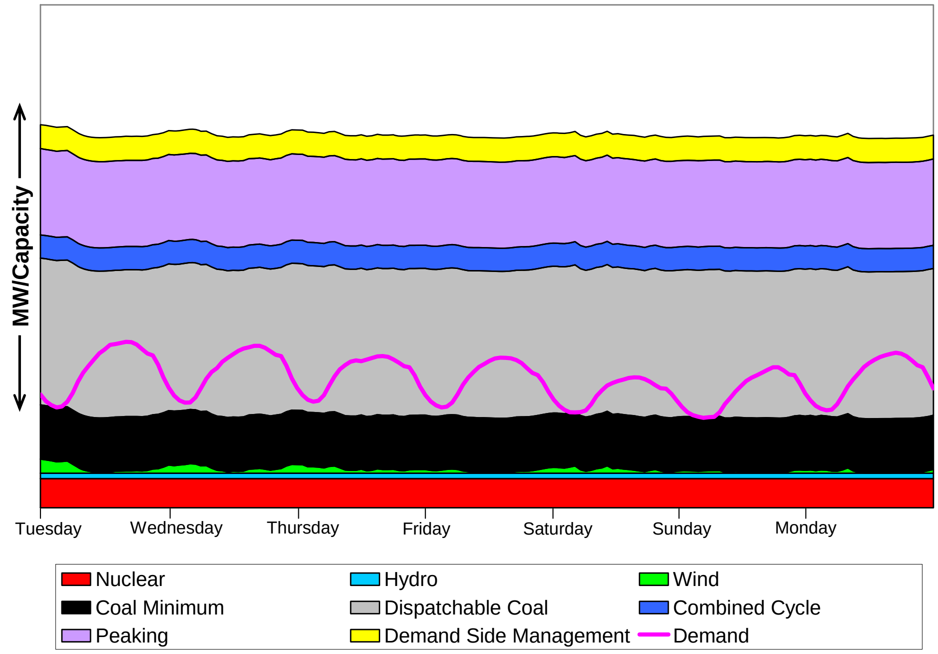
System operational issues are expected to increase as wind penetration levels increase. The following operating issues have been identified by the MRO Scenario Assessment Task Force:

- Managing Minimum Generation Limits During Light Load Conditions
- Ramp Requirements and Out-of-Phase Ramping
- Contingency Reserve Concerns
- Increased Risk of Baseload Unit Retirements
- Lower System Inertia
- Ambient Temperature Operating Limits
- Impacts on Protective Relaying
- Accurate Day Ahead and Hourly Wind Forecasting
- Operating Guides and Special Protection Systems
- Outage Coordination
- Congestion Management

**(a) Managing Minimum Generation Limits During Light Load Conditions**

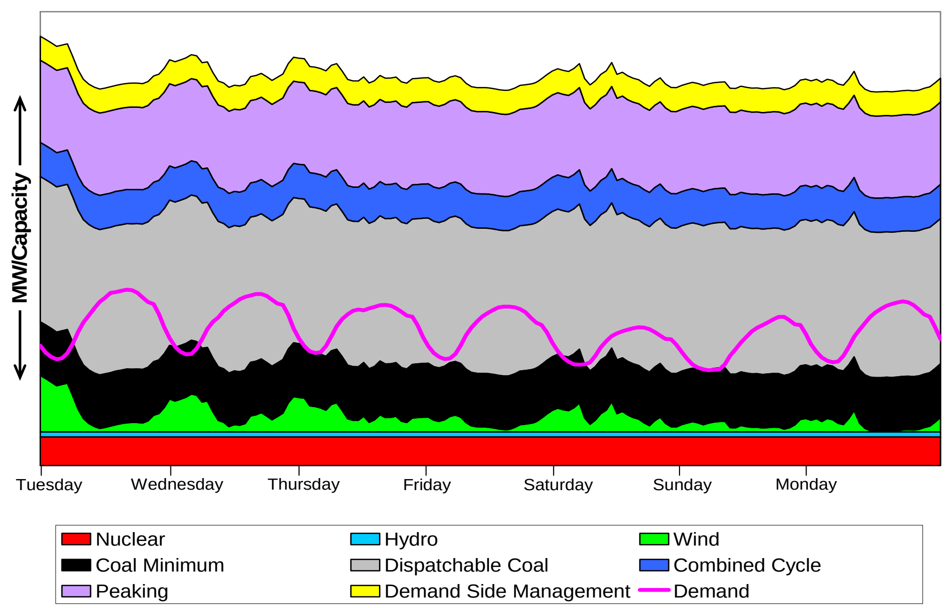
Large additions of wind generation present a challenge in managing the baseload fleet day-ahead commitment. Figure MRO-4 shows a simplified example using actual wind and demand curves for the MRO-US sampled from one week during 2008. Coal-fired plants were dispatched so that the total minimum capacity of coal production was equal to the minimum demand.

**Figure MRO-4: 2008 Load Level Simplified Example of Minimum Generation**




By escalating the 2008 demand to the 2017 levels, increasing nameplate wind by 15 percent, and adding projected capacity from the applicable Generator Interconnection queues yields the 2017 operations example in Figure MRO-5. As a conservative approach, no additional diversity was considered in Figure MRO-5.

**Figure MRO-5: 2017 Load Level Simplified Example of Minimum Generation**



Because of the potential inverse relation between wind production and demand, the production curve begins to dip below the coal minimum output levels during off-peak hours. Potential solutions to address this issue include:

- **Shut down baseload coal plants and increase gas utilization.** Most coal units have a substantial start-up time and high start-up costs. As dependence on gas increases, production costs would increase by using gas over coal.
- **Curtail wind generation outputs.** Minimal costs are associated with curtailing wind. However, if the asset is being used to meet a State RPS, curtailment could result in a utility falling short of the requirement. Furthermore, plentiful wind energy periods are often concurrent with light-load or shoulder-peak system loading conditions, such as late evening during Spring and Fall, such that the consequent amount of unused wind energy is likely substantial.

**(b) Ramp Requirements and Out-of-Phase Ramping**

Ramp is the increase or decrease of generation required to meet changes in load and wind generation across an hour. Wind generation ramps can have an inverse correlation to daily load ramps resulting in the need for additional reserves to support ramp. As more wind generation is added to the system, the magnitude and direction of ramping requirements are expected to increase. Figures MRO-6 and MRO-7 use the real-time actual system information from the 2008 peak week (July 27, 2008 through August 2, 2008) to display the relationship between wind generation levels and their corresponding ramp characteristics.

**Figure MRO-6: July 27, 2008 – August 2, 2008 MRO-US Real-Time Ramp Requirement**

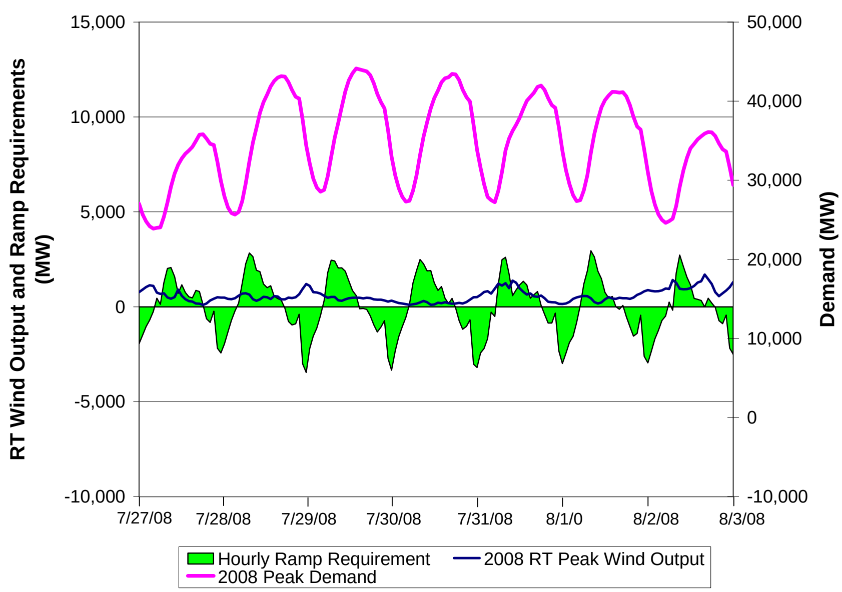


Figure MRO-7 displays the 2017 summer peak projected ramp characteristics obtained by escalating the 2008 wind generation and peak demand to the 2017 levels. As a conservative approach, no additional diversity was considered in Figure MRO-7.

**Figure MRO-7: 2017 MRO-US Ramp Requirements Escalated from July 27, 2008 – August 2, 2008 Real-Time Data**

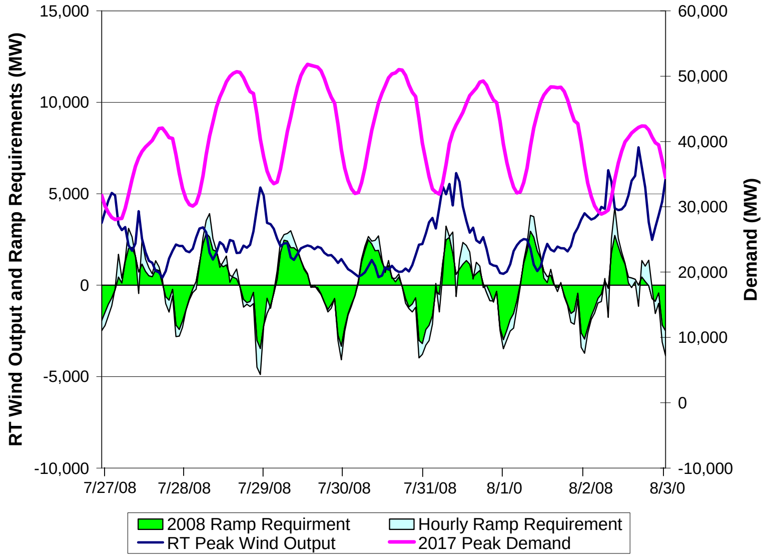



Table MRO-3 summarizes the differences in ramp requirements between the 2008 peak week and the 2017 projected peak. Both the amplitude (average positive/negative ramp and maximum positive negative ramp) and volatility (number of sign changes) increase with the added wind.

**Table MRO-3: MRO-US Peak Week Ramp Requirement Comparison**

| | 2008 | 2017 |
|---|---|---|
| Average Negative Ramp | 1,255 MW | 1,567 MW |
| Average Positive Ramp | 1,196 MW | 1,582 MW |
| Number of Hours Positive | 86 | 83 |
| Number of Hours Negative | 82 | 85 |
| Number of Sign Changes | 20 | 30 |
| Maximum Positive Ramp | 2,953 MW | 4,261 MW |
| Maximum Negative Ramp | 3,462 MW | 4,888 MW |

**(c) Contingency Reserve Concerns**

Contingency reserves may need to increase with large quantities of wind generation online. This is due to the variability of wind generation, as well as the reliability of day-ahead wind availability forecast. The unanticipated failure of wind to sustain the forecast quantity of output may result in inadequate amount of contingency reserve to make up the shortfall. This consideration would require the Balancing Authority to take a conservative stance and require more contingency reserves be available in the day-ahead market. The variability and ramping characteristics of wind turbine output would also require additional spinning and contingency reserve margins, both positive and negative, the precise amount of which changes day to day depending on the quality of Regional wind prevalence. These factors would dictate that day-ahead Ancillary Service Market (ASM) must be closely coordinated with wind forecasts and real-time monitoring of wind output.

**(d) Increased Risk of Baseload Unit Retirements**

Baseload units reduce market price volatility and provide reliable operational reserve margins, precisely the characteristics needed in an environment striving to accommodate large-scaled wind power integration. Many of these facilities are located where their dynamic reactive capabilities are also crucial to voltage regulation and local system reliability. However, when wind penetration reaches a level where many of these older and less efficient baseload facilities become sporadically dispatched day-in and day-out, there is the danger of their owners retiring these facilities.

**(e) Lower System Inertia**

More wind generation is being added which tends to lower the system inertia. During light load periods baseload units maybe displaced with wind generation, which contributes no inertia. The lack of system inertia has a negative impact on system stability, especially in the MRO footprint where transmission distances are typically long.

**(f) Ambient Temperature Operating Limits**

The standard thermal limitation on a wind generator is -20 degrees Celsius (-4 degrees Fahrenheit). Many wind generation owners in the MRO Region purchase the “cold weather package” to increase the thermal limit to -30 degrees Celsius (-22 degrees Fahrenheit). The area in MRO with abundant wind is concentrated in a corridor where extreme cold weather may likely occur simultaneously, affecting all facilities in the area. If such extreme weather was not accurately forecasted day-ahead, automatic shutdown of a large amount of wind output in a short time span could occur.

**(g) Impacts on Protective Relaying**

Wind facilities contribute minimal fault current in the event of a system disturbance. The lack of adequate fault current may in turn jeopardize the applicability of many local system protection schemes. This issue has not been dealt with in the industry enough for protection engineering to develop guidelines for relaying scheme changes. To date, experiences in the MRO footprint have not raised significant concern, as real-life experiences in the Buffalo Ridge area with ground faults since 2003 have indicated zero sequence current sources and short-circuit current contributions from the transmission system have been adequate in clearing faults within normal time. However, some perplexing misoperations of some digital relays had been observed, the root cause of which have not been totally understood. It is imperative, therefore, that the issue of short-circuit current be rigorously studied and understood.

**(h) Accurate Day-Ahead and Hourly Wind Forecasting**

An aspect of wind generation is the limited ability to predict with reasonable confidence what the output level would be at some time in the future. Conventional plants also cannot be counted on with 100 percent confidence to produce their rated output at some coming hour since mechanical failures or other circumstances may limit their output to a lower level or even result in the plant being taken out of service. The probability that this would occur in the near term, however, is low.

The Midwest ISO uses a centralized wind forecasting program in its market footprint to capture reliability and economic aspects of integrating wind into the day ahead and real-time markets. The forecast is based on the latitude and longitude of each wind farm and the hub heights of the wind turbines at that site. The real-time MW value is also provided to the wind forecast vendor. Each individual Commercial Pricing Node (CPN) is forecasted for each hour for the next seven days. The program uses a Multi Numerical Weather Prediction (NWP) model to come up with its best estimate for each node, zone, Region, and Midwest ISO total.

As wind penetration levels increase the forecast accuracy becomes essential to operate a reliable system. Additionally, accurate wind forecasts and timely updates are necessary in order to incorporate wind generation into the day-ahead market.

As of the summer of 2008, the largest decrease in wind production for the Midwest ISO Reliability Coordinator footprint was approximately 1,200 MW during a one-hour period. Because of the overall Midwest ISO system size compared to the size of this drop, the effects were minimal. The Midwest ISO has not experienced an inability to meet demand due to a lack of wind production.

**(i) Operating Guides and Special Protection Systems**

Although certain wind generation can provide counterflows in normally congested areas, more often there are challenges for the Midwest ISO Reliability Coordinator to manage this variable generation because much of it is being added as an Energy Resource and is utilizing available transmission capacity on a non-firm basis. Typically, transmission is constructed to accommodate conventional generation capacity that can be dispatched and that capacity usually comes online after the transmission upgrades are made. Many owners of wind generation are also financing upgrades to the transmission system, however, the generation usually gets built first, and the transmission may follow months or years later. Often times a Special Protection System (SPS) is installed to automatically mitigate overloads. These SPSs and operating guides present operating challenges to the Midwest ISO Reliability Coordinator and to the system operators in the Region. Operators would need to implement operating guides quickly which would be a challenge with the increasing number of guides available.

**(j) Outage Coordination**

Although accurate wind generation forecasts have been routinely achieved 24 to 48 hours out in the future, wind cannot be forecast with any accuracy out two to three weeks, which is the time frame required to assess transmission maintenance outages. Transmission maintenance outages may need to be evaluated with the worst-case assumptions regarding wind generation.

**(k) Congestion Management**

Presently wind generation is not fully integrated into the Midwest ISO market processes. Wind generation is considered a self-scheduled resource that runs whenever the fuel source is present.

It is a price taker, it does not participate in the day-ahead market, and it is exempt from deviation penalties. Conventional generation typically dispatches around wind generation.

As wind penetration increases, there would be occasions when wind would need to participate in congestion management, which can occur through operating guides, the use of SPSs, TLR procedure, or curtailment of wind generation. With the Production Tax Credit of $19/MWh (after tax), the wind plants can economically generate even with a negative Locational Marginal Price (LMP) as low as about -$29/MWh (before tax).

Ultimately, wind generation would likely participate in the day-ahead markets. This can be accomplished to a large extent with accurate forecasting. The Midwest ISO has 24-hour wind forecast, which is typically within plus or minus 10 percent of actual levels. Wind generation, to a reasonable extent, can be controlled so as to limit ramp rates, perform fast runback for contingencies, etc. However, it would require the integration of wind farm management systems with Market operator dispatch signals.

### Reliability Assessment Analysis

It is assumed that new wind facilities to be integrated onto the MRO footprint would comply with FERC Order 660-1A which addresses the need for low-voltage ride-through capabilities and reactive power capabilities of individual wind turbines. In the Midwest ISO, reactive power analysis is one integrated part of every individual Generation Interconnection System Impact Study. No wind plant can be granted interconnection services without mitigating the incremental reactive support problem it would cause. The Midwest ISO Ancillary Service Market and the Midwest Contingency Reserve Sharing Group provide financial incentives and legal obligations to ensure the entire Midwest ISO system has adequate frequency response support in both the short term and long term. The Midwest ISO believes wind forecast accuracy is critical to minimizing unexpected ramps in wind production, which in turn would minimize the requirement for additional reactive and frequency support requirements. Generator characteristics would be reviewed to identify more responsive units, which also may alleviate reactive or frequency response issues.

The Midwest ISO is actively working with its stakeholders to determine the best solution to be able to incorporate large amounts of wind. Accurate wind forecasts for the Day Ahead market process and accurate and timely updates during the operating day would need to occur in order to incorporate wind generation into the day-ahead market. Equitably allocating costs for reserve sharing would also need to be developed.

## Scenario Assessment for the MRO-Canada Subregion

### Manitoba

Manitoba Hydro's currently planned renewable capacity additions include 300 MW of wind capacity and 90 MW of hydro capacity. The wind generation is currently planned to be added in increments of 100 MW in 2011/12, 2012/13, and 2013/14. To serve future load obligations, an additional 90 MW of new hydro generation is also planned for a 2017/18 in-service date. This 90 MW installation would be the first unit of a new 695 MW hydro plant expected to be completed by 2020.

Resource adequacy is expected to improve as the hydro resource listed above is installed. However, the additional wind power would not be able to contribute capacity to meet Manitoba's winter peak, as the wind turbines would be shut down due to low temperature (colder than -20°F at times the winter peak occurs). The 90 MW of hydro would be dispatchable and would serve as a 90 MW capacity resource. The amount of external resource that Manitoba would have to rely on to meet planning reserve margins is not expected to change as these new resources become available.

From a transmission adequacy standpoint, sufficient new transmission is planned to be built to ensure deliverability of the added resources. Manitoba Hydro's study methodology for a Network Resource assumes full nameplate generation is available at peak load for determining the necessary transmission infrastructure.

The wind resources within Manitoba are located fairly close to major load centers or major 230 kV stations and transmission lines. An exploratory study was first performed that analyzed the transmission requirements for alternative locations of 300 MW of new wind in Manitoba. The study concluded there are numerous locations where wind can be economically and reliably interconnected.

The preferred location for the 300 MW wind project is the Letellier 230 kV station, which is about 60 miles south of Winnipeg. Manitoba Hydro is planning to construction a third 2,000 MW HVdc bipole line by 2017 to enhance the reliability of HVdc transmission system from its northern generation to load centers in southern Manitoba. The hydro generation identified above would be delivered to load over this new HVdc bipole line.

The reactive power requirements for a hydro plant are similar to a wind plant. The hydro plant must provide a minimum of 0.9 leading and lagging power-factor capability as measured at the machine terminals. The hydro plants must also provide automatic voltage control and a high initial response excitation system with a power system stabilizer because of the unit size. The wind plant must provide 0.95 leading and lagging power at the point of interconnection at nominal voltage and full output. Some deviations are permissible based on the terminal voltage. The wind plant must also provide voltage regulation. A full range of disturbances are applied to determine if the reactive power capability is adequate to meet NERC and MRO planning standards.

Frequency response is not a concern for a hydro generator. However, depending on the penetration level, frequency response can be a concern for a wind plant. Manitoba Hydro performs the worst case nearby generator trip disturbances at maximum wind output and monitors the under-frequency performance. A limit on the amount of wind that can be connected would be put in place if the transient under-frequency approaches the first setpoint of the under-frequency load-shed relays. Alternatively, the wind plant would be required to provide inertial response. The 300 MW wind addition that is described above is not expected to cause any frequency response issues.

Any wind located within Manitoba would be integrated into the market alongside existing resources within Manitoba. No market changes are required or assumed. However, there may be a benefit in sharing area control error differences between Manitoba and adjacent subregions.

### Saskatchewan

SaskPower currently has 172 MW of installed wind capacity and has plans to add 25 MW in 2011 and an additional 200 MW by 2013.

### Region Description

*The Midwest Reliability Organization (MRO) has 48 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and/or Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant and Transmission System Operator. The MRO has 19 Balancing Authorities (prior to Midwest ISO BA consolidation) and 116 registered entities. The MRO Region as a whole is a summer peaking Region. The MRO Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is approximately 1,000,000 square miles with an approximate population of 20 million.*

## MRO-Appendix A

**Figure MRO-A.1: JCSP Transmission Overlay for Reference Scenario for MRO-US**

**Figure MRO-A.2: JCSP Transmission Overlay for 20 percent Wind Scenario for MRO-US**

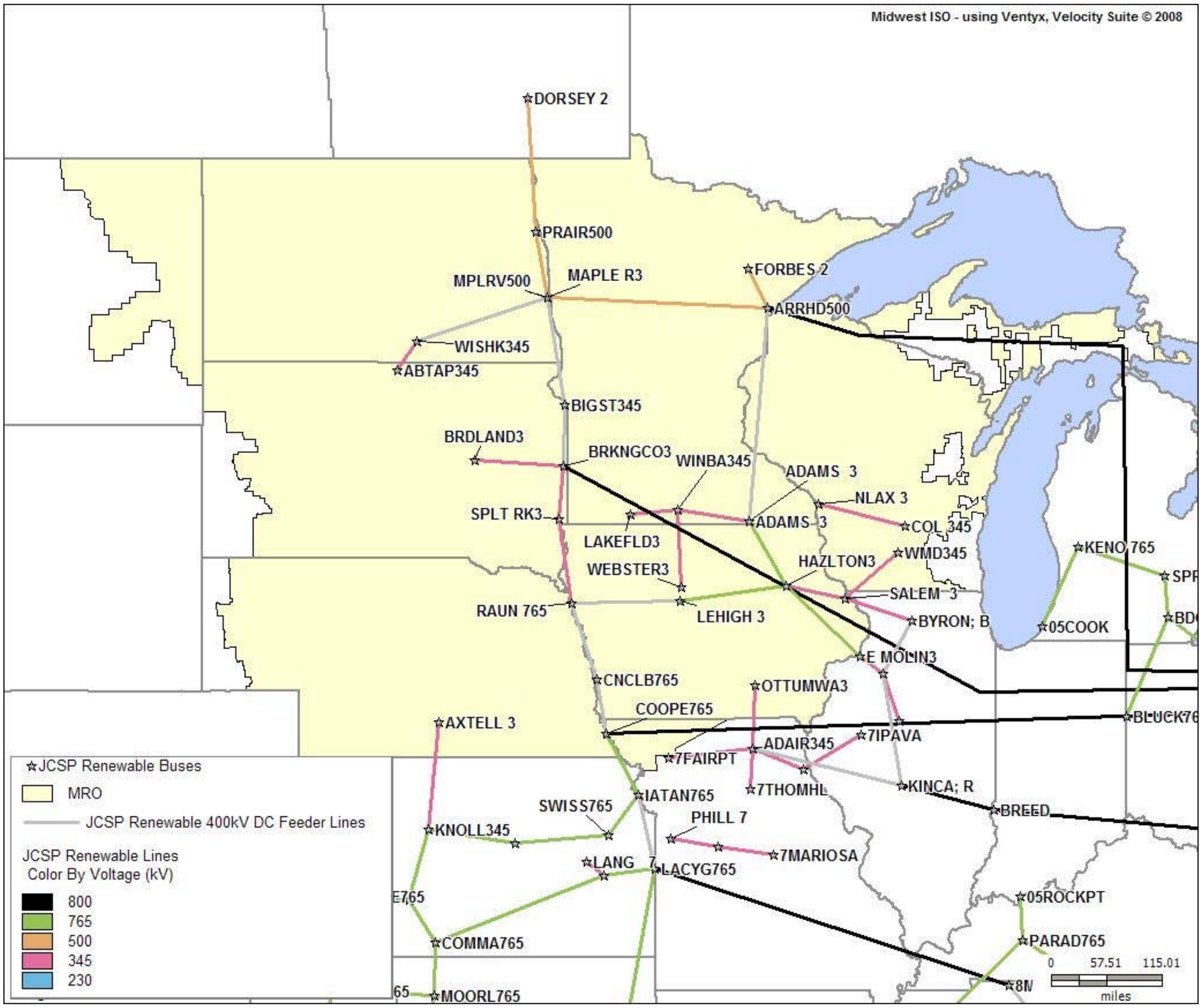


**Table MRO-A.1: JCSP-Added Transmission Lines for *Reference Case* and 20 percent Wind *Scenario Case* for MRO-US**

| TO BUS | FROM BUS | kV | Line Miles | Ref. Case Future | 20 percent Wind Future |
|---|---|---|---|---|---|
| LAKEFIELD 345 | WINNEBAGO 345 | 345 | 50 | X | X |
| WINNEBAGO 345 | ADAMS 345 | 345 | 74.6 | X | X |
| NLAX 345 | COLUMBIA 345 | 345 | 94 | X | X |
| LEHIGH 345 | HAZELTON 345 | 345 | 113 | X | |
| HAZELTON 345 | SALEM 345 | 345 | 64 | X | X |
| SALEM 345 | W MIDDLETON 345 | 345 | 74 | X | X |
| PRAIRIE 345 | ANTELOPE 345 | 345 | 226 | X | |
| HETTINGER 345 | BELFIELD 345 | 345 | 61 | X | |
| WISHEK 345 | HETTINGER 345 | 345 | 146 | X | |
| WAHPETON 345 | WISHEK 345 | 345 | 143 | X | |
| OAHE 345 | HETTINGER 345 | 345 | 152 | X | |
| OAHE 345 | FT THOMPSON 345 | 345 | 54 | X | |
| FT THOMPSON 345 | BROOKINGS 345 | 345 | 144 | X | |
| FT THOMPSON 345 | SIOUX CITY 345 | 345 | 189 | X | |
| SIOUX CITY 345 | LEHIGH 345 | 345 | 111 | X | |
| WINNEBAGO 345 | LEHIGH 345 | 345 | 85 | X | |
| FAIRPORT 345 | THOMAS HILL 345 | 345 | 97.9 | X | |
| OTTUMWA 345 | THOMAS HILL 345 | 345 | 108 | X | |
| THOMAS HILL 345 | PALMYRA 345 | 345 | 61 | X | |
| PRAIRIE 500 | DORSEY 500 | 500 | 139 | X | X |
| MAPLE RIVER 500 | PRAIRIE 500 | 500 | 80.3 | | X |
| MAPLE RIVER 345 | PRAIRIE 345 | 345 | 80.3 | X | |
| BIG STONE 345 | MAPLE RIVER 345 | 345 | 107 | X | X |
| BROOKINGS 345 | BIG STONE 345 | 345 | 63 | X | X |
| BROOKINGS 345 | SPLIT ROCK 345 | 345 | 54.5 | X | X |
| HAZLETON 765 | ADAMS 765 | 765 | 78 | | X |
| ANTVLY-BRDLD TAP | ANTELOPE 345 | 345 | 115 | | X |
| MAPLE RIVER 500 | ARROWHEAD 500 | 500 | 225 | | X |
| FORBES 500 | ARROWHEAD 500 | 500 | 53 | | X |
| WISHEK 345 | ANTVLY-BRDLD TAP | 345 | 40 | | X |
| ANTVLY-BRDLD TAP | BROADLAND 345 | 345 | 150 | | X |
| WISHEK 345 | JAMESTOWN 345 | 345 | 67.4 | | X |
| BROADLAND 345 | BROOKINGS 345 | 345 | 91 | | X |
| WINNEBAGO 345 | WEBSTER 345 | 345 | 81 | | X |
| SALEM 345 | BYRON 345 | 345 | 74 | | X |
| RAUN-LEHIGH TAP 345 | LEHIGH 345 | 345 | 65.7 | | X |
| RAUN-LEHIGH TAP 345 | DENISON 345 | 345 | 27 | | X |
| DENISON 345 | SCRANTON 345 | 345 | 48 | | X |
| SCRANTON 345 | GUTHRIE CNTR 345 | 345 | 24 | | X |
| GUTHRIE CNTR 345 | ANITA 345 | 345 | 22.4 | | X |
| CBLUF-MADISON TAP | MADISON 345 | 345 | 60 | | X |
| CBLUF-MADISON TAP | ANITA 345 | 345 | 20 | | X |
| LEHIGH 765 | RAUN 765 | 765 | 114 | | X |

| | | | | | |
|---|---|---|---|---|---|
| RAUN 765 | C BLUFFS 765 | 765 | 82 | | X |
| C BLUFFS 765 | COOPER 765 | 765 | 60 | | X |
| COOPER 765 | IATAN 765 | 765 | 72 | | X |
| ADAIR 345 | OTTUMWA 345 | 345 | 65 | | X |
| E MOLINE 345 | KEWANEE 345 | 345 | 31 | | X |
| SPLIT ROCK 345 | RAUN 765 | 345 | 88.2 | | X |
| LEHIGH 765 | HAZLETON 765 | 765 | 111 | | X |
| HAZLETON 765 | E MOLINE 765 | 765 | 107 | | X |
| ADAMS | E MOLINE | 400 HVdc | 183 | X | |
| C BLUFFS | THOMAS HILL | 400 HVdc | 203 | X | |
| ARROWHEAD | ADAMS | 400 HVdc | 223 | | X |
| WISHEK | MAPLE RIVER | 400 HVdc | 137 | | X |
| MAPLE RIVER | BIG STONE | 400 HVdc | 113 | | X |
| BIG STONE | BROOKINGS | 400 HVdc | 63.1 | | X |
| LEHIGH | RAUN | 400 HVdc | 115 | | X |
| RAUN | C BLUFFS | 400 HVdc | 84.5 | | X |
| C BLUFFS | COOPER | 400 HVdc | 58 | | X |
| ARROWHEAD | LUDLOW | 800 HVdc | | | |
| ARROWHEAD | HADDM NK | 800 HVdc | | | |
| ADAMS | EAST SHORE | 800 HVdc | | | |
| ADAMS | NORWALK | 800 HVdc | 1620 | | X |
| WISHEK | PLEASANTVILLE | 800 HVdc | | | |
| MAPLE RIVER | HUDSON | 800 HVdc | | | |
| BIG STONE | W 49 ST | 800 HVdc | | | |
| BROOKINGS | GOWANUS | 800 HVdc | 1450 | | X |
| LEHIGH | SOUTH CANTON | 800 HVdc | | | |
| RAUN | SOUTH CANTON | 800 HVdc | | | |
| C BLUFFS | SOUTH CANTON | 800 HVdc | | | |
| COOPER | SOUTH CANTON | 800 HVdc | 1300 | | X |

| **Table MRO-A.2: JCSP-Added Transformers for *Reference Case* and 20 percent Wind *Scenario Case* for MRO-US** | | | | |
|---|---|---|---|---|
| **TO BUS** | **FROM BUS** | **kV** | **Ref. Case Future** | **20 percent Wind Future** |
| PRAIRIE 345 | PRAIRIE 230 | 345/230 | X | |
| HETTINGER 345 | HETTINGER 230 | 345/230 | X | |
| WISHEK 345 | WISHEK 230 | 345/230 | X | X |
| WAHPETON 345 | WAHPETON 230 | 345/230 | X | |
| OAHE 345 | OAHE 230 | 345/230 | X | |
| WINNEBAGO 345 | WINNEBAGO 161 | 345/161 | X | X |
| PRAIRIE 500 | PRAIRIE 230 | 500/230 | X | |
| MAPLE RIVER 500 | MAPLE RIVER 345 | 500/345 | | X |
| BIGSTONE 345 | BIGSTONE 230 | 345/230 | X | X |
| HAZELTON 765 | HAZELTON 345 | 765/345 | | X |
| ADAMS 765 | ADAMS 345 | 765/345 | | X |
| E MOLINE 765 | E MOLINE 345 | 765/345 | | X |
| PRAIRIE 500 | PRAIRIE 230 | 500/230 | | X |
| ARROWHEAD 500 | ARROWHEAD 345 | 500/345 | | X |
| LEHIGH 765 | LEHIGH 345 | 765/345 | | X |
| RAUN 765 | RAUN 345 | 765/345 | | X |
| CBLUFFS 765 | CBLUFFS 345 | 765/345 | | X |
| COOPER 765 | COOPER 345 | 765/345 | | X |

# NPCC

The scenario analysis for the NPCC Region as part of the NERC Long Term Reliability Assessment for 2009 assumed incremental renewable resources to provide an additional 15 percent (a maximum of 5 percent made up from Energy Efficiency) of the requirements for the year 2018 for the Reliability Coordinator Balancing Authorities within NPCC (Maritimes, New England, New York, Ontario and Québec). The comparisons are judged against the *Reference Case* and data presented in the *2009 Long Term Reliability Assessment Reference Case.* The Québec area is an asynchronous Interconnection with over 90 percent of its energy produced by renewable resources over the ten-year time frame of the *Long-Term Reliability Assessment*, and, its future energy production would continue to be sourced through renewable resources. In the remaining four areas, a total of 15,230 MW of wind generation is assumed to be in service:

| | |
|---|---|
| Maritimes | 2,350 MW |
| New England | 3,380 MW |
| New York | 8,000 MW |
| Ontario | 1,500 MW |

Upon the assumption of this addition of renewable capacity, planning reserve margins increase significantly for the study year of 2018.

Because of the variable characteristics of wind generation, each of the NPCC areas is addressing the operational challenges of integrating large amounts of intermittent resources. These include increased periods of operation at minimum load and the need for increased regulation and load following.

The *Scenario Case* reports no specific bulk power transmission additions. However, within NYISO and ISO-NE, the planning process would identify and integrate renewable resources into the system; the NYISO has also recognized that some portions of the system may realize local constraints, which could result in some amount of undeliverable wind energy. The IESO expects that new 500 kV transmission west of its London substation would be needed to support the addition of the proposed wind resources. The New Brunswick System Operator estimates 400 miles of 138 kV construction would be required. Increased system voltage support in many local areas would also be necessary.

Although the incorporation of significant amounts of renewable capacity would be a challenge, it is believed that these resources would be reliably integrated.

## Maritimes

### Executive Summary

The 2009 Maritimes Area Scenario Analysis considers the integration of an additional 1,700 MW of wind capacity in the year 2018, or 15 percent of the 2018 annual net energy requirement. When combined with over 650 MW of wind capacity in 2018 from the 2009 Maritimes subregion *Long-Term Reliability Assessment*, the total amount of wind capacity considered in this *Scenario Case* exceeds 2,350 MW.

The 2,350 MW wind capacity target exceeds 40 percent of the 2018 winter peak load and 65 percent of the 2018 summer peak load. The key issue to achieving such large-scale wind integration is the Regional balancing of wind resource variability, both within the Maritimes subregion as well as between the Maritimes subregion and the neighboring jurisdictions of Québec and ISO New England.

### Introduction

The footprint of the Maritimes subregion is comprised of the provinces of New Brunswick (served by the New Brunswick System Operator), Nova Scotia (served by Nova Scotia Power Inc.), Prince Edward Island (served by the Maritime Electric Company Ltd.) and the Northern Maine Independent System Administrator, Inc (NMISA). The NMISA serves approximately 40,000 customers in northern Maine and is radially connected to the New Brunswick power system. The Maritimes Area is a winter peaking Region.

The 2009 Maritimes Area Scenario Analysis considers the integration of an additional 1,700 MW of wind capacity in the year 2018, or 15 percent of the 2018 annual net energy requirement. When combined with over 650 MW of wind capacity in 2018 from the 2009 Maritimes subregion *Long-Term Reliability Assessment*, the total amount of wind capacity considered in this *Scenario Case* exceeds 2350 MW.

Key assumptions used in the 2009 Maritimes Area Scenario Analysis include:

- Additional 15 percent of 2018 annual net energy from renewable resources.
- Assuming a 30 percent average capacity factor, the 15 percent additional renewable energy requirement in 2018 equates to 1,700 MW of wind capacity.
- The total wind capacity considered for 2018 in the *Scenario Case* exceeds 2,350 MW, and includes over 650 MW from the 2009 Maritimes Area *Long-Term Reliability Assessment* plus 1,700 MW.
- Assuming that the 1,700 MW of additional wind is supplied by 20 projects, and using an estimate of 20 miles of new 138 kV transmission line per project, it is estimated that 400 miles of new 138 kV transmission line is required in the *Scenario Case*.

The *Reference Case* is the 2009 Maritimes Area *Long-Term Reliability Assessment*.

### Demand
Demand in the *Scenario Case* is unchanged from the *Reference Case*.

### Generation
2018 wind capacity in the *Scenario Case* is 1,700 MW greater than 2018 wind capacity in the *Reference Case*. The total 2018 wind capacity in the *Scenario Case* exceeds 2,350 MW.

### Capacity Transactions on Peak
Capacity transactions on peak in the *Scenario Case* are unchanged from the *Reference Case*.

### Transmission
New transmission assumed in the *Scenario Case* versus the *Reference Case* is 400 miles of new 138 kV lines. This assumption is based on using 20 wind projects to supply the 1,700 MW of additional wind capacity, and that each wind project would require an average of 20 miles of new 138 kV transmission line.

### Operational Issues
The key issue to achieving such large-scale wind integration is the Regional balancing of wind resource variability, both within the Maritimes subregion as well as between the Maritimes subregion and the neighboring jurisdictions of Québec and New England. This Regional balancing may be achieved by allowing dynamic schedule changes or the Regional dispatch of resources.

Other operational issues that significantly affect the successful integration of large scale wind capacity include:

- Accurate wind forecasting.
- Curtailment control of wind resources.
- Good geographic distribution of wind resources to mitigate variability.
- Overall availability of balancing resources, both generation and load.

### Reliability Assessment Analysis
For 2018, the addition of 1,700 MW of wind capacity in the *Scenario Case* increases the winter reserve margin from 35 percent to 48 percent, and increases the summer reserve margin from 119 percent to 129 percent.

## New England

### Executive Summary

For the 2009 *Scenario Reliability Assessment*, ISO New England Inc. (ISO-NE) has chosen Scenario #1 for its 2009 *Scenario Case*.

This 2009 *Scenario Reliability Assessment* postulates the impacts on system reliability with respect to the rapid materialization of new renewable resources within New England. This 2009 *Scenario Reliability Assessment* also offers insights into the details of the potential operational problems these types of resources may bring to grid operations and sheds light on the potential solutions to mitigate those problems.

It should be noted that while ISO-NE has chosen Scenario #1 for its 2009 *Scenario Case*, and that Scenario #1 is based upon an assumption that the NERC Regions of MRO, NPCC, RFC, and SPP would all be building their 2009 *Scenario Cases* from the results and findings of the Joint Coordinated Study Group's[39] (JCSG) ―Joint Coordinated System Plan (JCSP), it should be emphasized that the NPCC members of NYISO and ISO New England did not sign the JCSP study report and have concerns with viewing the scenario transmission development as a "plan".[40] PJM also recognizes the need for conducting further analysis prior to considering any JCSP plan final. Additional background information on the JCSG's JCSP can be found in the *Joint Coordinated System Plan* section of this document.

### Introduction

The 2009 NERC *Long-Term Reliability Assessment Reference Case* was used as a base case to develop portions of the *Scenario Case*. In fact, the corresponding spreadsheets are almost the same. The two main differences between the *Reference Case* and the *Scenario Case* are within the projections for the build-out of Energy Efficiency, as well as changes in the amount of conceptual capacity additions that were assumed to materialize on the system.

For New England, the *Scenario Case* is essentially an assessment of operable capacity. ISO-NE made only two significant input assumption changes from the 2009 *Long-Term Reliability Assessment Reference Case*: 1) a reduction to energy demand as a result of new Energy Efficiency programs, and 2) a change in the amount of conceptual additions that were assumed to materialize on the system, all of which is new, supply-side renewable capacity. This 2009 *Scenario Case* compares resultant operable capacity margins against those within the 2009 *Long-Term Reliability Assessment Reference Case*. Other issues have been identified, which focus primarily on the potential impacts on system operations; a discussion is provided about the potential solutions to those problems. A comprehensive overview of the study results are also provided.

For the target year assessment of 2018, the *Scenario Case* assumed that approximately 5 percent of the annual energy use and was reduced from the *Reference Case* projections in order to simulate the resultant impact from new Energy Efficiency programs materializing within New

[39] More information about the JCSG study can be found at: http://www.jcsgstudy.com
[40] For more details on this decision, see http://www.iso-ne.com/pubs/pubcomm/corr/2009/2009-2-4_jcsp.pdf

England, as stipulated within the Scenario #1 requirement. Therefore, 5 percent of the overall 15 percent, which are supposed to come from new renewable resources, comes in the form of new demand-side resources within the category of Energy Efficiency.

In keeping with ISO-NE's prior treatment of reflecting demand-side resources as supply-side capacity, within the *Scenario Case*, there were no reductions taken to projected peak demands. The peak demand reductions associated with the impacts of the new Energy Efficiency programs are shown as equivalent supply-side capacity within the line item for Conceptual Capacity. Reductions were made to the associated energy use projections, as mandated by the Scenario #1 requirement.

Building on the assumption above, the remaining 10 percent of the overall 15 percent, which are supposed to come from new renewable resources, comes in the form of new renewable supply-side resources that are currently within the ISO Generation Interconnection Queue ("ISO-NE Queue") and are assumed to materialize by the target year 2018.

For the summer 2018 target assessment year, the *Reference Case* assumed approximately 12,462 MW of Conceptual Capacity. However, beginning with this year's NERC *Long-Term Reliability Assessment* submittal, a 20 percent Confidence Factor[41] has been applied to this amount of Conceptual Capacity Resources. This 20 percent Confidence Factor represents the amount of Conceptual Capacity that may become commercialized within the Region, starting in the year 2010. This 20 percent Confidence Factor is held constant going forward in time. In the summer of 2018, this equates to approximately 2,492 MW. For the same summer 2018 target assessment year, the *Scenario Case* assumed approximately 4,654 MW[42] of the *Reference Case*'s Conceptual Capacity would be commercial by 2018. That 4,654 MW of capacity consists of renewable generation projects within the ISO-NE Queue, which are mostly new wind capacity (87 percent), with minor capacity contributions (13 percent) from the combination of biomass, small hydro-electric, landfill gas, and fuel cell technologies.

The main assumption of the *Scenario Case* is that if only the amount of renewable capacity that is currently proposed within the ISO-NE Queue is commercialized, these projects generate enough electric energy on an annual basis to satisfy over 11.1 percent of the annual energy demand in 2018. When combined with the assumed 5 percent reduction in annual peak demand (in the form of supply-side capacity) and a 5 percent reduction in overall energy use as a result of new Energy Efficiency contributions, then over 16 percent of the forecast annual energy use would be met by new renewable resources, as mandated by the Scenario #1 requirement.

The 2009 *Long-Term Reliability Assessment Reference Case* that was submitted by ISO-NE identified three open issues going forward that could possibly impact system reliability. Those three issues were the potential impact on Regional capacity (and resource adequacy) from:

[41] This 20 percent value for the Confidence of Conceptual Resources was developed from a historical trend that reflects the amount of capacity that has commercialized from within ISO-NE's Generator Interconnection Queue. Within the 2009 LTRA *Reference Case*, ISO-NE's Conceptual Capacity reflects all the remaining capacity within the ISO-NE Generator Interconnection Queue that has not been classified as either Future, Planned or Future, Other – Capacity Additions.

[42] This amount of *Scenario Case* Conceptual Capacity has an associated Confidence Factor of 100 percent.

1) A potentially large influx of new, intermittent capacity resources like wind generation.[43] Currently, New England has very little existing wind capacity (less than 100 MW of nameplate), but concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the corresponding build-out of these new supply-side resources in the near-term. Because of this and other operational concerns, ISO-NE is currently embarking on a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid. This wind study will also propose solutions to those problems.

2) The unknowns associated with upcoming nuclear plant relicensing that is scheduled to occur within a 3 to 16 year time frame,[44] and,

3) The potential need to modify, refurbish, or retire both river and coastal, steam-generation power plants that currently use *"once-through"* cooling with *"closed-loop"* cooling systems. Current rulemaking at the United States EPA, which has been recently ruled on by the U.S. Supreme Court, injects uncertainty into the process for which revised NPDES[45] water permits may soon mandate cooling tower arrangements in order to reduce the impact on aquatic life due to power plant cooling operations.

The first issue (#1) is an emerging operational issue. The last two issues (#2 and #3) can be combined and categorized as a potential loss of operable capacity, with that potential loss being either temporary or permanent in nature. The reliability impacts stemming from the last two issues equate to a resource adequacy issue.

This *Scenario Case* that is submitted by ISO-NE includes these same *Reference Case* unknowns concerning new wind power development, nuclear plant relicensing, and the potential need for retrofitting closed-loop cooling, but more importantly, it identifies several key issues with respect to potential impacts on system operations which could result from the postulated rapid influx of new renewable resources into New England's power system. Aside from the straight-forward comparisons of capacity margins and resource adequacy between the 2009 *Long-Term Reliability Assessment Reference Case* and this *Scenario Case*, the *Scenario Case* deals more with trying to identify and gauge the impacts on system operations due to the commercialization of numerous types of new supply and demand-side technologies.

It should be noted, however, that a short-coming of this *Scenario Case* is that many of these new, supply-side renewable resources like wind that are not yet fully commercialized within the Region. Also, the numerous amounts of demand-side resources which are spearheading the installation of new "smart-grid" technologies within the field, are technologies that are new to New England, and subsequently, are relatively unknown with respect to grid operations. Thus, these new supply and demand-side resources have minimal operating hours from which to

[43] Currently, ISO-NE has approximately 2,500 MW (total) of new onshore & offshore wind projects requesting study within its Generation Interconnection Queue.
[44] Within New England, approximately 1,300 MW of nuclear capacity has their current NRC Operating License expiring within a three-year timeframe and approximately 3,350 MW of nuclear capacity has their current NRC Operating License expiring within a sixteen-year timeframe.
[45] The National Pollutant Discharge Elimination System (NPDES).

observe the actual way in which they have or would eventually operate, and as such, a historical perspective is unavailable for both modeling and planning purposes.

Table New England-1 provides a comparison between the *Reference Case* and the *Scenario Case* for the various types of NERC Reserve Margins for the summer 2018 target assessment year.

| **Table New England -1 – Comparison of 2018 Summer Margins: Reference versus *Scenario Case*** | | |
|---|---|---|
| **2018 Summer Margins:** | ***Reference Case* (%)** | ***Scenario Case* (%)** |
| Region/Sub-Region Target Capacity Margin | N/A | N/A |
| Region/Sub-Region Target Reserve Margin | N/A | N/A |
| Existing Certain and Net Firm Transactions | 7.1 | 7.1 |
| Total Potential Resources | 53.2 | 28.0 |
| Adjusted Potential Resources | 20.2 | 27.2 |

Due to the fact that ISO-NE uses a probabilistic methodology[46] to determine resource adequacy needs, both the 2018 Summer Reserve Margin for the category *Region/Sub-Region Target Capacity and Reserve Margins* are labeled "Not-Applicable (N/A)", for both the *Reference Case* and *Scenario Cases*. Within prior NERC *Long-Term Reliability Assessment* submittals, these two values have not applied, and unless ISO-NE changes its forward-going methodology to determine New England's annual resource adequacy requirements, they would not apply going forward.

The NERC 2018 Summer Reserve Margins for the category *Existing Certain and Net Firm Transactions* shows a 7.1 percent margin for both the *Reference Case* and the *Scenario Case*. This is because both the *Reference* and the *Scenario Case* have the same assumptions for Existing (Certain and Other) Capacity, Future (Planned and Other) Capacity and Capacity Transactions (Imports and Exports).

The 2018 Summer Reserve Margins for the category *Total Potential Resources* shows a 53.2 percent margin for the *Reference Case* and a 28.0 percent margin for the *Scenario Case*. This difference is due to the fact that within both the *Reference Case* and the *Scenario Case*, 100 percent of the identified Conceptual Capacity was added to the *Total Potential Resources* margins. The *Reference Case* Conceptual Capacity (12,462 MW) is 7,808 MW greater than that of the *Scenario Case* Conceptual Capacity (4,654 MW). The *Reference Case Total Potential Resources* margin (53.2 percent) is almost twice as much as that of the *Scenario Case Total Potential Resources* margin (28 percent).

The 2018 Summer Reserve Margins for the category, *Adjusted Potential Resources*, shows a 20.2 percent margin for the *Reference Case* and a 27.2 percent margin for the *Scenario Case*.

[46] ISO-NE uses the Loss of Load Expectation (LOLE) method for determining New England's annual resource adequacy needs, which in short, accounts for the probabilistic variations in both load and resource availability.

This difference is due to the fact that within the *Scenario Case*, a 100 percent Confidence Factor was applied to the Conceptual Capacity, thus adding the total amount of renewable resources (4,654 MW) to the *Adjusted Potential Resources* margins. However, the *Reference Case* only applies a 20 percent Confidence Factor (Line 16c) to the total amount of Conceptual Capacity (12,462 MW), which results in approximately 2,492 MW of resources being applied to the *Adjusted Potential Resources*, which results in a margins of only 20.2 percent.

## Demand

The *Scenario Case* demand forecast was based on the 2009 *Long-Term Reliability Assessment Reference Case* demand forecast, which was based on the most recent reference economic forecast, which reflects the economic conditions that "most likely" would occur. The key factor leading to the lower 2009 *Long-Term Reliability Assessment* forecast, as compared to the 2008 *Long-Term Reliability Assessment* forecast, is the current economic downturn which has significantly impacted the forecast of peak loads and energy demand within the New England Region, resulting in approximately a one to two year delay in achieving the same demand levels that had been previously predicted in the 2008 forecast.

As noted earlier, the 2009 NERC *Long-Term Reliability Assessment Reference Case* projected peak and energy demands were used within the *Scenario Case*. However, for the *Scenario Case*, only the monthly and yearly energy demands were modified (within the associated spreadsheet) by taking a percentage reduction in quantity for energy demand from the corresponding *Reference Case* projections, ramped in at a rate of 0.5 percent per year starting in 2009 and compounding out to the year 2018 to 5.0 percent.[47] This 5 percent overall energy reduction in the target assessment year of 2018, represents the impacts that accelerated integration of Energy Efficiency initiatives would ultimately have upon peak loads and energy demand. For the target assessment year of 2018, the *Reference Case* energy demand of 142,125 GWh was adjusted downward by a total of 5 percent, to become the *Scenario Case* energy demand of 135,019 GWh, a difference of 7,106 GWh or -5 percent.

However, in keeping with ISO-NE's prior treatment of reflecting demand-side resources as supply-side capacity, there was no reduction of projected peak demand within the *Scenario Case*. The peak demand reductions associated with the impacts of the new Energy Efficiency programs are shown as equivalent supply-side capacity, combined with other supply-side resources within the line item for Conceptual Capacity. As stated earlier, reductions were made only to the associated energy demand projections, as mandated by the Scenario #1 requirement. Table New England-1-1 and Table New England-1-2 highlight this discussion in detail.

[47] This represents annual percentage reductions of: 2009 (0.5%), 2010 (1.0%), 2011 (1.5%), 2012 (2.0%), 2013 (2.5%), 2014 (3.0%), 2015 (3.5%), 2016 (4.0%), 2017 (4.5%), and 2018 (5.0%).

| **Table New England-1-1: *Scenario Case* Energy Efficiency Impacts on Summer Peak Demand Projections and Resultant Supply-Side Capacity Adders to Summer Conceptual Capacity.** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Category** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **1. *Reference Case* Summer Peak Hour Demand (MW)** | **27,875** | **28,160** | **28,575** | **29,020** | **29,365** | **29,750** | **30,115** | **30,415** | **30,695** | **30,960** |
| **2. Energy Efficiency (EE) Build-Out ( percent)** | **0.5 %** | **1.0 %** | **1.5 %** | **2.0 %** | **2.5 %** | **3.0 %** | **3.5 %** | **4.0 %** | **4.5 %** | **5.0 %** |
| **3. Energy Efficiency Reduction (MW)** | **139** | **282** | **429** | **580** | **734** | **893** | **1,054** | **1,217** | **1,381** | **1,548** |
| **4. Energy Efficiency in *Reference Case* (MW)** | **506** | **641** | **890** | **767** | **767** | **767** | **767** | **767** | **767** | **767** |
| **5. EE Needed for Summer Peak Demand *Scenario Case* (MW)** | **0** | **0** | **0** | **0** | **0** | **126** | **287** | **450** | **614** | **781** |
| **6. EE Supply-Side Capacity *Scenario Case* Summer Capacity (MW)** | **0** | **0** | **0** | **0** | **0** | **126** | **287** | **450** | **614** | **781** |

Line 1 shows the *Reference Case* Summer Peak Hour Demand (MW). Line 4 shows the yearly Energy Efficiency impacts in the form of supply-side capacity (MW) which was included within the 2009 *Long-Term Reliability Assessment Reference Case*. Line 5 represents the difference between the Energy Efficiency capacity reductions (MW) mandated by the *Scenario Case* (line 3) from those contained within the *Reference Case*. Where the Energy Efficiency within the *Reference Case* (line 4) is greater than what is needed within the *Scenario Case* (line 3), the resultant Energy Efficiency (EE) supply-side adder (line 5) is zero. Where the Energy Efficiency within the *Reference Case* (line 4) is less than what is needed within the *Scenario Case* (line 3), the resultant Energy Efficiency supply-side adder (line 5) is the (positive) difference between the two values. As noted earlier, in keeping with ISO-NE's prior treatment of reflecting demand-side resources as supply-side capacity, these Energy Efficiency (EE) Supply-Side Adders (line 6) are subsequently added as equivalent capacity to the *Scenario Case* Summer Conceptual Capacity (MW) line item, as shown in Table New England 2-5 (line 15).

Table New England 1-2 shows the *Scenario Case* Energy Efficiency Impacts on Winter Peak Demand Projections and Resultant Supply-Side Capacity Adders to Winter Conceptual Capacity. The same methodology described above is applicable to the *Scenario Case* Winter Conceptual Capacity (MW) line item, as shown in Table New England 2-6 (line 15).

**Table New England-1-2 – *Scenario Case* Energy Efficiency Impacts on Winter Peak Demand Projections and Resultant Supply-Side Capacity Adders to Winter Conceptual Capacity**

| Category | 2009 2010 | 2010 2011 | 2011 2012 | 2012 2013 | 2013 2014 | 2014 2015 | 2015 2016 | 2016 2017 | 2017 2018 | 2018 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1. *Reference Case* Winter Peak Hour Demand (MW) | 22,100 | 22,105 | 22,175 | 22,290 | 22,335 | 22,440 | 22,540 | 22,645 | 22,750 | 22,860 |
| 2. Energy Efficiency (EE) Build-Out (percent) | 0.5 | 1.0 | 1.5 | 2.0 | 2.5 | 3.0 | 3.5 | 4.0 | 4.5 | 5.0 |
| 3. Energy Efficiency Reduction (MW) | 110 | 221 | 333 | 446 | 558 | 673 | 789 | 906 | 1,024 | 1,143 |
| 4. Energy Efficiency in *Reference Case* (MW) | 506 | 626 | 872 | 751 | 751 | 751 | 751 | 751 | 751 | 751 |
| 5. Demand-Side EE Needed for Winter Peak Demand *Scenario Case* (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 38 | 155 | 273 | 392 |
| 6. EE Supply-Side Capacity Adders to *Scenario Case* Winter Conceptual Capacity (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 38 | 155 | 273 | 392 |

The method described above outlines how the *Scenario Case*'s 5 percent of seasonal (summer and winter) peak demand were theoretically reduced from the *Reference Case* projections in order to simulate the resultant impact from new Energy Efficiency programs materializing within New England, as stipulated within the Scenario #1 requirement. Therefore, 5 percent of the overall 15 percent, that is supposed to come from new renewable resources, comes in the form of new, demand-side resources within the category of Energy Efficiency, but reflected as supply-side capacity within the Conceptual Capacity line item of the associated spreadsheet.

## Generation

Within the *Scenario Case*, the same assumptions were used for Existing (Certain and Other) Capacity that was used within the 2009 *Long-Term Reliability Assessment Reference Case*. The difference between the two cases, *Scenario Case* versus *Reference Case*, lies within the assumptions for Conceptual Capacity. Within the 2009 *Long-Term Reliability Assessment Reference Case*, Conceptual Capacity[48] reflected all types of projects that were defined within the ISO-NE Generator Interconnection Queue, as of the March 15, 2009 publication. Within the *Scenario Case*, only the "queue" renewable projects, as mandated by the Scenario #1 requirement, were included within the Conceptual Capacity. These renewable projects within the ISO-NE queue include wind, biomass/wood waste, landfill gas, hydro-electric, and fuel cells. These projects represent the accelerated integration of renewable resources that the mandate of Scenario #1 required.

Although the nameplate capacity of these projects reflect the renewable technologies of wind, biomass, landfill gas, hydro, and fuel cells, some portions of that renewable (future) capacity that would have been categorized as Conceptual Capacity were already categorized as Future, Planned and Future, Other Capacity within the 2009 *Long-Term Reliability Assessment Reference Case*. Therefore, within the *Scenario Case*, to obtain the nameplate capacities shown in Table New England 2-3, you must combine the individual components identified in Table New England 2-5 (summer), to equal the overall nameplate capacities identified in Table New England 2-3. The same is true of the winter capacities. Within the *Scenario Case*, to obtain the nameplate capacities shown in Table New England 2-4, you must combine the individual components identified in Table New England 2-6 (winter), to equal the overall nameplate capacities identified in Table New England 2-4.

Table New England 2-1 shows the *Scenario Case* Renewable Capacity Additions by the year of commercialization. Please notice the renewable wind capacity is broken into both onshore and offshore values. A breakdown of the renewable capacity (by type) by year and associated energy production from those renewable resources, at their assumed annual capacity factor, is shown in Table New England 2-2, for the years 2009 through 2014. Since there are no projects in the ISO-NE Queue that have in-service dates past 2014, it is assumed all the renewable resources are installed by 2014.

**Table New England-2-1: *Scenario Case* Renewable Capacity Additions by Year of Commercialization**

| Renewable Capacity Type (MW) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total MW | % of Total |
|---|---|---|---|---|---|---|---|---|
| **Onshore Wind** | 0 | 193 | 1,005 | 786 | 809 | 108 | **2,901** | **67.8 %** |
| **Offshore Wind** | 0 | 0 | 462 | 0 | 347 | 20 | **829** | **19.4 %** |
| **Biomass** | 8 | 190 | 49 | 140 | 0 | 100 | **487** | **11.4 %** |
| **Landfill Gas** | 0 | 34 | 0 | 0 | 0 | 0 | **34** | **0.8 %** |
| **Hydro** | 0 | 15 | 2 | 0 | 0 | 0 | **17** | **0.4 %** |
| **Fuel Cell** | 0 | 9 | 0 | 0 | 0 | 0 | **9** | **0.2 %** |
| **Annual Capacity Totals** | **8** | **441** | **1,518** | **926** | **1,156** | **228** | **4,277** | **100 %** |

***Note: Sums may not equal totals due to rounding.***

48 As noted earlier, a 20 percent Confidence Factor was applied to the total amount of *Reference Case* Conceptual Capacity.

| Table New England-2-2: *Scenario Case* Renewable Capacity Annual Energy Contributions By Project Type by Year of Commercialization | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Renewable Capacity Type** | **Capacity Factor (%)** | **2009 GWh** | **2010 GWh** | **2011 GWh** | **2012 GWh** | **2013 GWh** | **2014 GWh** | **Total GWh** |
| **Onshore Wind** | 32 % | 0 | 541 | 2,817 | 2,203 | 2,268 | 303 | **8,132** |
| **Offshore Wind** | 37 % | 0 | 0 | 1,497 | 0 | 1,125 | 65 | **2,687** |
| **Biomass** | 90 % | 63 | 1,498 | 386 | 1,104 | 0 | 788 | **3,840** |
| **Landfill Gas** | 90 % | 0 | 268 | 0 | 0 | 0 | 0 | **268** |
| **Hydro** | 25 % | 0 | 33 | 4 | 0 | 0 | 0 | **37** |
| **Fuel cell** | 95 % | 0 | 75 | 0 | 0 | 0 | 0 | **75** |
| | | | | | | | | |
| **Annual Energy Totals** | | **63** | **2,415** | **4,705** | **3,307** | **3,392** | **1,156** | **15,039** |
| **Cumulative Annual Energy Totals** | | **63** | **2,478** | **7,183** | **10,490** | **13,883** | **15,039** | |

***Note: Sums may not equal totals due to rounding.***

- Onshore wind capacity totals approximately 2,901 MW, which at an assumed annual capacity factor of 32 percent, equates to approximately 8,132 GWh of renewable energy production by 2014.
- Offshore wind capacity totals approximately 829 MW, which at an assumed annual capacity factor of 37 percent, equates to approximately 2,687 GWh of renewable energy production by 2014.
- Biomass capacity totals approximately 487 MW, which at an assumed annual capacity factor of 90 percent equates to approximately 3,840 GWh of renewable energy production by 2014.
- Landfill gas capacity totals approximately 34 MW, which at an assumed annual capacity factor of 90 percent equates to approximately 268 GWh of renewable energy by 2014.
- Hydro-electric capacity totals approximately 17 MW, which at an assumed annual capacity factor of 25 percent equates to approximately 37 GWh of renewable energy production by 2014.
- Fuel cell capacity totals approximately 9 MW, which at an assumed annual capacity factor of 95 percent equates to approximately 75 GWh of renewable energy production by 2014.

Total renewable capacity is 4,277 MW, which at the various assumed annual capacity factors of each technology type, equates to approximately 15,039 GWh of renewable energy production by 2014. Assuming these renewable projects commercialize by their target dates and stay online, this annual energy production value can be transferred to the target assumption year of 2018.

Then at the year 2018, this renewable energy contribution is roughly equivalent to approximately 11.1 percent of the target year 2018 *Scenario Case* annual energy forecast of 135,019 GWh. When coupled with the 5 percent annual energy reduction due to new Energy Efficiency build-out, the combined renewable energy contributions (16.1 percent) clearly represent the Scenario #1 mandate of having over 15 percent of the annual energy contribution from new renewable resources by 2018 (including Energy Efficiency at no more than 5 percent).

Table New England 2-3 shows the *Scenario Case* Renewable Summer Capacity Cumulative Additions by Year of Commercialization.

**Table New England-2-3: *Scenario Case* Renewable Summer Capacity Cumulative Additions by Year of Commercialization**

| *Summer (MW)* | *2009* | *2010* | *2011* | *2012* | *2013* | *2014* |
|---|---|---|---|---|---|---|
| ***Wind*** | *0* | *193* | *1,660* | *2,446* | *3,602* | *3,730* |
| ***Biomass*** | *8* | *198* | *247* | *387* | *387* | *487* |
| ***Landfill Gas*** | *0* | *0* | *34* | *34* | *34* | *34* |
| ***Hydro*** | *0* | *15* | *17* | *17* | *17* | *17* |
| ***Fuel Cell*** | *0* | *9* | *9* | *9* | *9* | *9* |
| | | | | | | |
| ***Totals*** | ***8*** | ***415*** | ***1,967*** | ***2,893*** | ***4,049*** | ***4,277*** |

***Note: Sums may not equal totals due to rounding.***

Table New England 2-4 shows the *Scenario Case* Renewable Winter Capacity Cumulative Additions by Year of Commercialization.

**Table 2-4 – *Scenario Case* Renewable Winter Capacity Cumulative Additions by Year of Commercialization**

| *Winter (MW)* | *2009/10* | *2010/11* | *2011/12* | *2012/13* | *2013/14* | *2014/15* |
|---|---|---|---|---|---|---|
| ***Wind*** | *287* | *1,350* | *2,446* | *3,602* | *3,730* | *3,730* |
| ***Biomass*** | *104* | *125* | *387* | *387* | *437* | *487* |
| ***Landfill Gas*** | *0* | *34* | *34* | *34* | *34* | *34* |
| ***Hydro*** | *8* | *16* | *17* | *17* | *17* | *17* |
| ***Fuel Cell*** | *0* | *9* | *9* | *9* | *9* | *9* |
| | | | | | | |
| ***Totals*** | ***399*** | ***1,534*** | ***2,893*** | ***4,049*** | ***4,227*** | ***4,277*** |

***Note: Sums may not equal totals due to rounding.***

As noted above, Tables New England 2-1 through Table New England 2-4 represent the amount of future renewable nameplate capacity that is assumed to materialize under the mandate of the Scenario #1 requirement. Correspondingly, Tables New England 2-5 and Table New England 2-6 represent this same amount of new renewable capacity, as categorized within the *Scenario Case* spreadsheet, broken out into the individual components of Future Capacity (Planned &

Other) and Conceptual Capacity. This is shown because the 2009 *Long-Term Reliability Assessment Reference Case* had already shown some of this new renewable capacity being commercialized in the near-term (thus shown as Future Capacity (Planned & Other). Those equivalent amounts of capacity had to be taken out of the remaining Conceptual Capacity line item.

One problem pertaining to wind capacity within the associated NERC spreadsheets is that when it is categorized as Conceptual Capacity, only nameplate capacity is used. When that same wind capacity becomes near-term commercial, and is placed into the Future Capacity line item, then the specific Future, Planned Wind Expected On-Peak and the Future, Other Wind Derate On-Peak Capacity must be defined using the existing market rules and site-specific wind information. Unfortunately, this information is not available for the majority of wind projects within the ISO-NE Queue, thus the reasoning for using nameplate wind capacity within both the Reference and *Scenario Case* Conceptual Capacity line items.

Although somewhat confusing, the *Scenario Case*'s new renewable capacity does match up between nameplate projections shown here (Table New England 2-1 through Table New England 2-4) and the individual capacity components defined within the corresponding *Scenario Case* spreadsheet (as shown in Table New England 2-5 and Table New England 2-6).

| Table New England-2-5: Components of Additional Scenario Case Summer Conceptual Capacity | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capacity Category (MW)** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Wind Expected On-Peak | 0 | 153 | 1,310 | 2,096 | 3,252 | 3,380 | 3,380 | 3,380 | 3,380 | 3,380 |
| Biomass Expected On-Peak | 8 | 196 | 228 | 368 | 368 | 468 | 468 | 468 | 468 | 468 |
| Hydro Expected On-Peak | 0 | 15 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| Fuel Cell Expected On-Peak | 0 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| EE Supply-Side Capacity Adders | 0 | 0 | 0 | 0 | 0 | 126 | 287 | 450 | 614 | 781 |
| **Summer Conceptual Capacity** | 8 | 373 | 1,563 | 2,489 | 3,645 | 2,770 | 4,160 | 4,323 | 4,487 | 4,654 |

| Table New England 2-6 – Components of *Scenario Case* Winter Conceptual Capacity | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capacity Category (MW)** | **2009 2010** | **2010 2011** | **2011 2012** | **2012 2013** | **2013 2014** | **2014 2015** | **2015 2016** | **2016 2017** | **2017 2018** | **2018 2019** |
| Wind Expected On-Peak | **287** | **1,310** | **2,096** | **3,252** | **3,380** | **3,380** | **3,380** | **3,380** | **3,380** | **3,380** |
| Biomass Expected On-Peak | **104** | **157** | **368** | **368** | **418** | **468** | **468** | **468** | **468** | **468** |
| Hydro Expected On-Peak | **8** | **16** | **16** | **16** | **16** | **16** | **16** | **16** | **16** | **16** |
| Fuel Cell Expected On-Peak | **0** | **9** | **9** | **9** | **9** | **9** | **9** | **9** | **9** | **9** |
| EE Supply-Side Capacity Adders | **0** | **0** | **0** | **0** | **0** | **0** | **38** | **155** | **273** | **392** |
| **Winter Conceptual Capacity** | **399** | **1,492** | **2,489** | **3,645** | **3,823** | **3,873** | **3,911** | **4,028** | **4,146** | **4,265** |

The discussion below pertains to the new renewable nameplate capacities identified in Tables New England 2-1 through Table New England 2-4 and not the *Scenario Case* spreadsheets.

As noted earlier, wind capacity was divided into both onshore and offshore wind. By the target year 2018, new onshore wind capacity totals approximately 2,901 MW. Applying an annual capacity factor of 32 percent, as derived from market rules and prior Regional wind studies, new annual onshore wind energy production is approximately 8,132 GWh of new renewable, variable energy production by 2018.

By the target year 2018, new offshore wind capacity totals approximately 829 MW. Applying an annual capacity factor of 37 percent, as derived from existing market rules and prior Regional wind studies, new annual offshore wind energy production is approximately 2,687 GWh of new renewable, variable energy production by 2018.

By the target year 2018, new hydro-electric capacity totals approximately 17 MW. Applying an annual capacity factor of 25 percent, as derived form historical analysis of non-dispatchable, run-of-river, hydro-electric facilities, new annual hydro-electric energy production is approximately 37 GWh of new renewable, variable energy production by 2018.

The discussion below pertains to the new renewable nameplate capacities identified in Tables 2-1 through Table New England 2-4 and not the *Scenario Case* spreadsheet.

As noted earlier, by the target year 2018, new (wood-based) biomass capacity totals approximately 487 MW. Applying an annual capacity factor of 90 percent, as derived from historical analysis of Regional biomass facilities, new annual biomass energy production is approximately 3,840 GWh of new, renewable energy production by 2018.

By the target year 2018, new landfill gas capacity totals approximately 34 MW. Applying an annual capacity factor of 90 percent, as derived from historical analysis of Regional landfill gas facilities, new annual landfill gas energy production is approximately 268 GWh of new, renewable energy production by 2018.

As can be seen in Tables New England 2-3 (summer) and Table New England 2-4 (winter), both tables show the *Scenario Case* Renewable Seasonal Capacity Cumulative Additions by Year of Commercialization. Since nameplate ratings have been used for the capacity values of these new renewable projects, there is no difference in the seasonal capacity (mix) ratings for the new renewable resources within the *Scenario Case*. A comparison of the generation mix between the Reference and *Scenario Case* follows.

The discussion below pertains to the capacities identified in Tables New England 2-5 and Table New England 2-6 as also shown within the *Scenario Case* spreadsheets.

As noted earlier, the 2009 *Long-Term Reliability Assessment Reference Case* was used as a base case to develop the 2009 *Scenario Case*. The two main differences between the cases are within the projections for Energy Efficiency, as well as changes in the amount of conceptual capacity additions that were assumed to materialize on the system.

For the target year assent of 2018, the *Reference Case* assumed approximately 12,462 MW of conceptual capacity, of which some portion could possibly be commercial by that date. However, beginning with this year's NERC *Long-Term Reliability Assessment* submittal, a 20 percent Confidence Factor[49] has been applied to this amount of Conceptual Capacity Resources. This 20 percent Confidence Factor represents the amount of Conceptual Capacity that may become commercialized within the Region, starting in the year 2010. This 20 percent Confidence Factor is held constant going forward in time. In the summer of 2018, this equates to approximately 2,492 MW.

The types of on-peak capacity assumed to be making up this amount are: 2,180 MW of wind, 468 MW of biomass, and 16 MW of hydro-electric technologies, and the rest (9,798 MW) being comprised of single-cycle or combined-cycles gas turbine projects, combustion turbine projects, a pumped storage project, internal combustion, and other small projects.

Since the 2009 *Scenario Reliability Assessment* focuses on Scenario #1—studying the effects of an accelerated integration of renewable resources, for the target assessment year of 2018, the *Scenario Case* assumed 4,654 MW of renewable-only, Conceptual Capacity, of which the entire portion would be commercial by 2018. The accompanying *Scenario Case* spreadsheet assumes a 100 percent Confidence Factor for all of this renewable conceptual capacity. This specific amount of capacity was the current amount of new, renewable capacity that is currently proposed within the ISO-NE Generator Interconnection Queue. Therefore, if all of this new renewable capacity is commercialized, under the *Scenario Case*, these projects would satisfy over 11.1 percent of the annual energy demand in 2018, and when combined with the assume 5 percent new Energy Efficiency contribution (totaling 16.1 percent), then over 15 percent of the forecast annual energy production would be met by renewable resources, as mandated by the Scenario #1 requirement.

In more detail for the year 2018, the 2009 *Long-Term Reliability Assessment Reference Case* wind capacity was assumed to be 2,530 MW[50] versus 3,730 MW[51] in the *Scenario Case*, a difference of 1,200 MW. This large difference in new wind project assumptions are the five (5) proposed wind projects, totaling 1,200 MW, proposed for Aroostook County, Maine. Currently, that part of the bulk power system is operated by NMISA, [52] which is not part of ISO New

[49] This 20 percent value for the Confidence of Conceptual Resources was developed from a historical trend that reflects the amount of capacity that has commercialized from within ISO-NE's Generator Interconnection Queue. Within the 2009 LTRA *Reference Case*, ISO-NE's Conceptual Capacity reflects all the remaining capacity within the ISO-NE Generator Interconnection Queue that has not been classified as either Future, Planned or Future, Other – Capacity Additions.

[50] For the summer of 2018, the 2,530 MW value includes 2,180 MW of Conceptual Wind Capacity plus 88 MW of Future, Planned On-Peak Wind Capacity plus 262 MW of Future, Other On-Peak Wind Derate Capacity.

[51] For the summer of 2018, the 3,730 MW value includes 3,380 MW of Conceptual Wind Capacity plus 88 MW of Future, Planned On-Peak Wind Capacity plus 262 MW of Future, Other On-Peak Wind Derate Capacity.

[52] The Northern Maine Independent System Administrator ("NMISA") was created in 1999 in response to the mandate of the legislature of the State of Maine that effective retail electric competition be available to all of Maine's electricity consumers by March 1, 2000. The NMISA's size, scope, purpose and electricity market were designed to facilitate the development and implementation of retail electric competition and foster Regional reliability efforts in the electrically isolated area of the state in portions of Aroostook, Washington and Penobscot Counties. Northern Maine is characterized by low population density and a very low electric demand in comparison with other electricity markets. *(continued in next page footnotes)*

England's Regional Balancing Authority, so those projects are currently not included with the ISO-NE Generation Interconnection Queue.[53] However, in keeping with the mandate of the Scenario #1 requirements, for the *Scenario Case*, it was assumed that these new, renewable wind projects would materialize, and due to their significant size[54] and the future need to satisfy Regional renewable portfolio standards (RPS), those projects would eventually be (by 2018) incorporated into either the New England (under ISO-NE Balancing Authority) or New Brunswick (NBSO Balancing Authority) power grids via new bulk transmission interconnections.

All of the other assumptions for Conceptual Capacity are the same between the *Reference Case* and the *Scenario Case*, which include:[55]

1) New biomass capacity, which was assumed to be 468 MW,
2) New hydro-electric capacity, which was assumed to be 16 MW,
3) New landfill gas capacity, which was assumed to be 34 MW, and
4) New fuel cell capacity, which was assumed to be 9 MW.

These common assumptions for non-wind Conceptual Capacity within both the Reference and *Scenario Cases* comprise a total of 527 MW.

Within both the 2009 *Long-Term Reliability Assessment* Reference and *Scenario Cases*, ISO-NE's Deliverable Capacity Resources amount to 34,499[56] MW in the summer of 2018. That

---

The dominant characteristics of the Northern Maine Market are its electrical isolation, large geographic size, small electric demand, and modest population. The electric system in Northern Maine is not directly interconnected with the rest of New England, including any other Maine utility or any other domestic electric system. NMISA participants, therefore, are not participants in the New England Power Pool (NEPOOL) and are not subject to the control of ISO New England ("ISO-NE"). The Region's only access to the electric system that serves the remainder of Maine and the rest of New England is through the transmission facilities of New Brunswick Power ("NB Power"). The New Brunswick System Operator ("NBSO") is the Balancing Authority and Reliability Coordinator ("RC") for the Balancing Authority Area that includes the Northern Maine and Maritimes Regions.

[53] As of the March 15, 2009 ISO-NE Generator Interconnection Queue, proposed projects were sorted into two categories: Category #1 = *Active – Administered Transmission System, which are Interconnection Requests to the Administered Transmission System, Generation and Elective Transmission Upgrade Requests, and Requests for Transmission Service* (These are FERC-regulated projects falling under the ISO-NE Open Access Transmission Tariff (OATT) - Schedules 22 and 23), and Category #2 = *Active – Affected System – Interconnection Requests for which the Administered Transmission System is an Affected System, Generation Requests* (These projects are either FERC-regulated projects that do not fall under the ISO-NE Open Access Transmission Tariff (OATT) Schedules 22 and 23, due to their interconnection location on the local or distribution system, or are non-FERC regulated projects on neighboring systems, that may impact the reliability of ISO-NE's bulk transmission system, and thus, require transmission interconnection studies by ISO-NE.

[54] Currently, the NMISA system is a winter-peaking system with native load forecast to be approximately 150 MW for the year 2018. The possible commercialization of 1,200 MW of the Aroostook wind projects is significantly more generation than is needed to satisfy own-load requirements, resulting in those projects being likely candidates for interconnecting to the New England system in order to sell their excess renewable "green" capacity and energy to Regional wholesale markets.

[55] Although the overall amounts of Conceptual Capacity assumptions are the same between the *Reference Case* and *Scenario Case*, some amounts of capacity reside within the Future (Planned and Other) Capacity line items. Also note that the Confidence Factors applied to the each of the Cases are different.

includes 33,244 MW of Existing, Certain generating capacity, -94 MW of net Capacity Transactions, and 1,349 MW of Future, Planned generating capacity additions. The *Reference Case* shows that ISO-NE has a total of 12,462 MW of Conceptual Capacity within its Generator Interconnection Queue,[57] with in-service dates ranging from 2009 to 2015. The *Scenario Case* shows that ISO-NE has only a total of 4,654 MW of Conceptual Capacity of new renewable capacity within the same Generator Interconnection Queue, with in-service dates ranging from 2009 to 2014. Although some projects that reside within the ISO-NE Generator Interconnection Queue have declared in-service dates of 2009 or 2010, some of those projects have not demonstrated viable pre-commercial activities and were categorized as conceptual capacity.

Within the *Reference* and *Scenario Cases*, Future, Planned wind capacity for the summer of 2018 includes 88 MW (350 MW nameplate with a 262 MW on-peak derate) of new wind capacity. *Reference Case* Conceptual wind capacity amounts to 2,180 MW while the *Scenario Case* Conceptual wind capacity amounts to 3,380 MW.

A total of 468 MW of Conceptual biomass capacity is proposed for installation in New England with target in-service dates of 2009 through 2014. This is the same assumption for the *Scenario Case*.

ISO-NE's capacity margin calculations include Planned Capacity Resources that are expected to begin commercial operation by the end of 2009. This information is based on either the date specified in a signed Interconnection Agreement, or discussions with the ISO indicating that the project is nearing completion and is preparing to become an ISO generator asset. Also included in the planned capacity resources are new projects that have obligations in the ISO-NE Forward Capacity Market through 2011—2012.

Within the *Scenario Case*, the same base assumption sets are used throughout the ten-year timeframe, except for the fact that the magnitude of Conceptual Capacity Resources[58] in the year 2018 is somewhat larger than those assumed for the *Reference Case*.

## Capacity Transactions on Peak

The same assumptions were used for Capacity Transactions for the 2009 *Scenario Case* that were used within the *Reference Case*, with respect to firm on-peak imports and exports. Under both cases, firm summer imports amount to approximately 401 MW in 2009, 899 MW in 2010, and 2,298 MW for 2011 and 2012. The imports for 2010 and 2011 reflect the Forward Capacity Auction results. The 2011 FCA results were assumed to remain in place in 2012. Since the FCA imports are based on one-year contracts, beginning in 2013 the imports reflect only known, long-term Installed Capacity (ICAP) contracts. Firm summer imports decrease to 334 MW in 2013 and 2014, and decrease again to 284 MW in 2015 and 112 MW in 2016, and then level off at 6 MW for the summers of 2017 and 2018.

[56] Due to differences in assumptions, the amount of existing and planned capacity in summer 2009 is different from that published in ISO New England's 2009-2018 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report).
[57] As of the March 15, 2009 ISO-NE Generation Interconnection Queue publication.
[58] After applying the individual, but different, Confidence Factors.

For the summer of 2009, ISO-NE reports a firm capacity export to New York (Long Island) of 343 MW, anticipated to be delivered via the Cross-Sound Cable. This sale will be reduced to 100 MW beginning in 2010. It should be noted that there is no firm transmission arrangement through the New England PTF system associated with this contract. This export is backed by a firm contract for generation, but because the power has to go through the Connecticut import constrained interface, and there is no firm transmission arrangement, it can be cut earlier than non-recallable exports in the case of a transmission import constraint into Connecticut. The export across the Cross-Sound Cable is based on a make-whole contract.

## Transmission

There are no differences between the *Reference Case* and the *Scenario Case* with respect to new bulk power transmission, transformer additions, and substation equipment. Although it is known that under the *Scenario Case*, to rapidly integrate the large amounts of renewable resources into New England's system, it is assumed that both local and bulk transmission would need to be added and/or modified to support such new, renewable infrastructure enhancements. However, the majority of these types of projects have multiple (transmission) interconnection proposals based on variations in possible future transmission topology and as such, the true amount of future new transmission infrastructure needed to incorporate these renewable projects is undetermined at this time. In a recent ISO-NE report, *2009 Economic Study: Scenario Analysis of Renewable Resource Development*[59], transmission needs are identified for a high-level of renewable generation scenario by 2030.

There are no differences between the *Reference Case* and the *Scenario Case* with respect to bulk power transmission additions. Table New England 4-1 lists significant transmission additions to the bulk power system that will influence reliability. These are the same transmission additions for the *Scenario Case* that were identified within the *Reference Case*.

**Table New England 4-1 – Significant Transmission Additions within the 2009 *Scenario Case***

| Transmission Project Name | Voltage (kV) | Length (Miles) | In-Service Date(s) | Description/Status |
|---|---|---|---|---|
| Short Term Lower SEMA Upgrades | 115 | 8.3 | Jun-2009 | Install second circuit from Carver to Tremont. |
| Greater Rhode Island Transmission Reinforcements | 115 | 3.4 | Jun-2011 | Install circuit from Somerset to Brayton Point. |
| Vermont Southern Loop Project | 345 | 51.2 | Jun-2011 | Install circuit from Vermont Yankee to Newfane to Coolidge. |
| NEEWS (Rhode Island Reliability Project) | 345 | 21.4 | Jun-2012 | Install circuit from Kent County to West Farnum. |

[59] http://www.nescoe.com/uploads/iso_eco_study_report_draft_sept_8.pdf

| Table New England 4-1 – Significant Transmission Additions within the 2009 *Scenario Case* | | | | |
|---|---|---|---|---|
| **Transmission Project Name** | **Voltage (kV)** | **Length (Miles)** | **In-Service Date(s)** | **Description/Status** |
| Maine Power Reliability Program | 345 | 184 | Dec-2012 | Install circuits from Orrington to Albion Road, Albion Road to Coopers Mills, Larrabee Road to Coopers Mills, Larrabee Road to Suroweic, Suroweic to Raven Farm, Maguire Road to South Gorham, and Maguire Road to Three Rivers. |
| Maine Power Reliability Program | 115 | 137 | Dec-2012 | Install circuits from Orrington to Coopers Mills, Coopers Mills to Highland, Larrabee Road to Livermore Falls, Gulf Island to Larrabee Road, Raven to East Deering, East Deering to Cape, and Livermore Falls to Section 243 junction. |
| NEEWS (Greater Springfield Reliability Project) | 345 | 18 | Dec-2013 | Install circuit from Agawam to North Bloomfield. |
| NEEWS (Interstate Reliability Project) | 345 | 29.3 | Dec-2013 | Install circuit from Card to Lake Road. |
| NEEWS (Interstate Reliability Project) | 345 | 7.6 | Dec-2013 | Install circuit from Lake Road to Connecticut/Rhode Island border (towards West Farnum). |
| NEEWS (Greater Springfield Reliability Project) | 345 | 16.8 | Dec-2013 | Install circuit from Ludlow to Agawam. |
| NEEWS (Interstate Reliability Project) | 345 | 20.7 | Dec-2013 | Install circuit from Millbury to West Farnum. |
| NEEWS (Central Connecticut Reliability Project) | 345 | 35.4 | Dec-2013 | Install circuit from North Bloomfield to Frost Bridge. |
| NEEWS (Interstate Reliability Project) | 345 | 17.7 | Dec-2013 | Install circuit from West Farnum to Connecticut/Rhode Island border (towards Lake Road). |
| Greater Rhode Island Transmission Reinforcements | 115 | 3.7 | Jan-2014 | Install third circuit from Somerset to Bell Rock. |

There are no differences between the *Reference Case* and the *Scenario Case* with respect to significant transformation additions. Table New England 4-2 lists significant transformer additions to the bulk power system that influence reliability. These are the same transmission additions for the *Scenario Case* that were identified within the *Reference Case*.

| Table New England 4-2 – Significant Transformer Additions within the 2009 *Scenario Case* | | | | |
|---|---|---|---|---|
| **Transformer Project Name** | **High-Side Voltage (kV)** | **Low Side Voltage (kV)** | **In-Service Date(s)** | **Description/Status** |
| Monadnock Area Reliability Project | 345 | 115 | Aug-2009 | Fitzwilliam Substation - Install one autotransformer. |
| Merrimack Valley/North Shore Reliability Project | 345 | 115 | Nov-2009 | Wakefield Jct Substation - Install four autotransformers. |
| Greater Rhode Island Transmission Reinforcements | 345 | 115 | Dec-2010 | Kent County Substation - Install second autotransformer. |
| Vermont Southern Loop Project | 345 | 115 | Jun-2011 | Vernon Substation - Install one autotransformer. |
| Western Massachusetts Upgrades | 230 | 115 | Oct-2011 | Bear Swamp Substation - Install one autotransformer. |
| Greater Rhode Island Transmission Reinforcements | 345 | 115 | Oct-2011 | Berry Street Substation - Install one autotransformer. |
| Western Massachusetts Upgrades | 345 | 115 | Dec-2011 | Wachusett Substation - Install third autotransformer. |
| Auburn Area Transmission System Upgrades | 345 | 115 | May-2012 | Auburn Substation - Install second autotransformer. |
| NEEWS (Rhode Island Reliability Project) | 345 | 115 | Jun-2012 | Kent County Substation - Install third autotransformer. |
| Long Term Lower SEMA Upgrades | 345 | 115 | Dec-2012 | Canal Substation – Move third autotransformer (#126) to Sandwich and install higher capacity autotransformer at Canal |
| Maine Power Reliability Program | 345 | 115 | Dec-2012 | Install autotransformers at Albion Substation, Coopers Mills, Larrabee Road Substation, Raven Farm Substation, Maguire Road Substation, and South Gorham Substation. |
| NEEWS (Greater Springfield Reliability Project) | 345 | 115 | Dec-2013 | Agawam Substation - Install two autotransformers. |
| NEEWS (Central Connecticut Reliability Project) | 345 | 115 | Dec-2013 | Frost Bridge Substation - Install second autotransformer. |

| Table New England 4-2 – Significant Transformer Additions within the 2009 *Scenario Case* | | | | |
|---|---|---|---|---|
| **Transformer Project Name** | **High-Side Voltage (kV)** | **Low Side Voltage (kV)** | **In-Service Date(s)** | **Description/Status** |
| NEEWS (Greater Springfield Reliability Project) | 345 | 115 | Dec-2013 | Ludlow Substation – Replace two autotransformers. |
| NEEWS (Greater Springfield Reliability Project) | 345 | 115 | Dec-2013 | North Bloomfield Substation - Install second autotransformer. |

There are no differences between the *Reference Case* and the *Scenario Case* with respect to new significant substation equipment. Within the *Scenario Case*, to rapidly integrate the large amounts of renewable resources into New England's power system, it is assumed that both local and bulk transmission substation equipment and other special devices would need to be added and/or modified to support such new, renewable infrastructure enhancements.

As a notable exception to the transmission statements above, there currently exists several bulk transmission interfaces on the New England system, which are currently impacted by thermal, stability, and voltage limitations. These transmission interfaces limit the free flow of power across the system. Assuming the mandate of an accelerated integration of renewable resources as mandated within the Scenario #1 requirement, it would be a safe assumption for New England that a majority of these new renewable resources that would be expected to be commercialized and operating during the target assessment year 2018, and thus would require some build-out of the exiting transmission system within the Region to accommodate the influx of 4,654 MW of new renewable capacity. Depending on where these projects are physically located and thus "electrically-located," they may either be on the "right-side" or "wrong-side" of an existing transmission interface, thus either helping to dampen the constraining effects of the transmission interface or exacerbating it. Aside from the standard supply-side resource interconnection process for which either a minimum transmission interconnection standard or a maximum[60] (output) transmission interconnection standard could be applied, some amount of additional transmission expansion would definitely be required to ensure the unconstrained delivery of this new renewable power throughout the existing ISO-NE system.

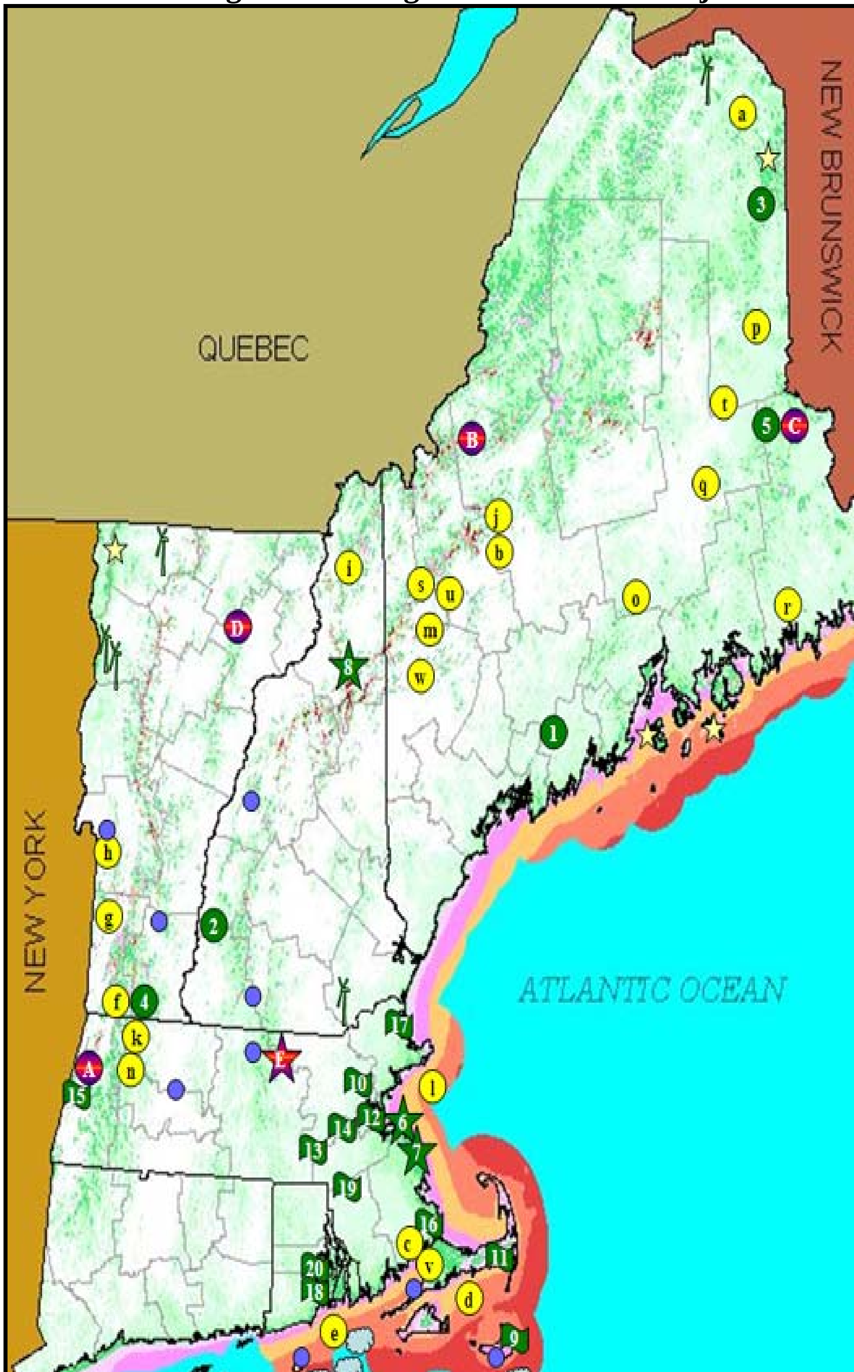
[60] Currently referred to within the Forward Capacity Market as the *Capacity Capability Interconnection Standard (CCIS).*

## Operational Issues

Within the *Reference Case*, for the summer of 2009, there is only 39 MW[61] of expected on-peak wind capacity on the New England system, so operational challenges from the integration of variable resources are negligible at this time. However, under the *Scenario Case*, 829 MW of onshore wind capacity and 2,901 MW of offshore wind capacity are assumed commercialized for the target assessment year 2018. With 3,730 MW of wind resources projected, the anticipated operational issues are currently being examined by ISO-NE. Figure New England-5-1 shows a map of planned and operating wind projects in New England.

[61] As of March 2009, almost 100 MW of nameplate, utility-scale wind generation projects were on line with in the ISO-NE system.

**Figure New England-5-1 – Wind Projects within New England**




## Operating Projects

### Wind Plants

1 Beaver Ridge
2 Lempster
3 Mars Hill
4 Searsburg
5 Stetson Ridge

### Community Scale

Hull Wind 1
Hull Wind 2
Jericho Mountain Wind

### Customer Sited (100 kW+)

8 Bartlett Farm
9 City of Medford
10 Country Garden Hyannis
11 Forbes Park
12 Holy Name Catholic High School
13 IBEW
14 Jiminy Peak
15 Massachusetts Maritime Academy
16 Mark Richey Woodworking Newburyport
17 Portsmouth Abbey
18 St. Mary's Abbey
19 Town of Portsmouth

### Small Wind (<100 kW)

Beaulieu
Burlington Electric Department
Butterworks Farm
Dynapower
Manchester/Hillsborough

| Type of Project | Operating | Permitted or Under Construction | Planned | Retired |
|---|---|---|---|---|
| Wind farm | | | | |
| Community scale | | | | |
| Customer sited (100 kW+) | | | | |
| Small wind (<100 kW) | | | | |

The generic issues for wind integration in New England are 1) transmission interconnection; 2) system flexibility; 3) operator awareness and practices; and 4) wind generation performance and standards.[62]

**Transmission:** Wind resources tend to be concentrated in areas of the power system, which historically had limited transmission capability. Expanding transmission would be a critical step in achieving the large-scale integration of wind. A significant amount of new transmission and/or enhanced utilization of existing transmission capability would be needed over the next several years to accommodate and integrate higher levels of wind generation into the interregional power system.

**System Flexibility:** The bulk power system would require increased ramping capability and resources that can be dispatched quickly to accommodate the increased variability and uncertainty of generation such as wind. Resource planning must ensure the bulk power system has the quantity of flexible supply and demand-side resources necessary to accommodate the increase in variable generation—e.g., storage capability or off-peak load such as plug-in hybrid electric vehicles. Markets, pricing regimes, and minimum standards should be developed to provide signals about the system characteristics that are most valued for both existing generators and for developers and entities that are planning new generation.

**Operator Awareness and Practices:** Enhancements are required to existing operator practices, techniques and decision support tools to increase the operator awareness of new variable generation and to operate future bulk power systems with large-scale penetration of wind generation. Wind generation must be visible to, and controllable by, the system operator, similar to any other power plant so the system operator can maintain reliability. For instance, the NYISO requires existing wind plants to be visible to system operations and is utilizing a short-term centralized wind forecast system for real-time operation to more accurately predict the magnitude and phase (i.e., timing) of wind generation plant output. In addition, based on its existing experience with operating wind plants, NYISO has proposed to its market participants that wind plants participate in the NYISO economic dispatch/congestion management system in order to fully optimize the economics of the wind plants while maintaining reliability.

**Wind Generation Plant Performance and Standards:** Interconnection and generating plant standards need to be enhanced to ensure that variable generation's design and performance contribute to reliable operation of the power system. These include the need to standardize basic requirements, such as:

- Power factor range (and thus reactive power capability)
- Voltage regulation
- Fault-ride through (low voltage and high voltage)

[62] The majority of this information was taken from the 2008 publication of the Northeast Coordinated System Plan (NCSP08), published on March 27, 2009 and located on the ISO-NE web site located at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2009/ncsp04-01-09.pdf

- Inertial-response (the effective inertia of the generation as seen from the grid is often zero)
- The ability to control the ramp rates (MW/minute) on wind turbines and/or curtail output
- The ability to participate in primary frequency control (governor action, automatic generation control, etc.)

In addition, improved wind plant models need to be developed, validated and standardized for all wind technologies, especially for use in conducting stability and transient analysis studies.

Appliance controllers and automated technologies that modify load characteristics, known as "smart-grid" technologies, can mitigate stress on the grid and prevent power outages during grid emergencies. Smart-grid technologies also can help integrate renewable energy resources into the grid and may reduce the need to build generation, transmission, and distribution systems. Technologies can provide ancillary services, and possibly storage, both of which would facilitate the integration of wind resources. However, further research and development work is necessary, and ISO-NE has undertaken a large, detailed wind integration study, which is outlined below.

**New England Wind Integration Study:**
In 2008, the ISO-NE issued a Request-For-Proposals (RFP) to conduct a New England Wind Integration Study (NEWIS).[63] The RFP has been awarded and the study is underway. A vendor team led by General Electric (GE) Energy Applications and Systems Engineering with support from three consultants (EnerNex, AWSTruewind, and WindLogics) is performing the comprehensive wind power integration study. All the work must be conducted during 2009 and 2010. The following subsections describe the drivers, goals, and the tasks of the ISO-NE study.

**Drivers**
Successfully integrating large amounts of wind power into the power system presents technical challenges because the characteristics of wind power generation differ significantly from conventional generation. These characteristics include limited controllability and high variability of power produced by wind turbines and the uncertainty with which that amount of power produced can be forecast. To some extent, the variability and uncertainty inherent to wind power can be mitigated by increasing the geographic diversity of the interconnected wind power resources. The operation and planning of the New England power system would be affected by the expansion of wind power resources in New York and neighboring Canadian provinces. These resource additions in neighboring Regions would likely provide opportunities for closer coordinated operation among the systems, additional interregional power transfers, and new bulk power transmission tie lines.

**Goals**
The goals of the NEWIS are as follows:

[63] Available on the ISO's Web site: http://www.iso-ne.com/aboutiso/vendor/exhibits/index.html.

a) To determine, for the ISO-NE Balancing Authority Area, the operational, planning, and market impacts of integrating large-scale wind power as well as the mitigating and facilitating measures available to ISO-NE
b) To make recommendations for implementing these mitigation and facilitation measures

In particular, the NEWIS will identify the potential adverse operating conditions created or exacerbated by the variability and unpredictability of wind power and recommend potential corrective activities for mitigating these adverse impacts. The study aims to capture the unique characteristics of New England's bulk electrical system and wind resources in terms of load and ramping profiles, geography, topology, supply and demand-side resource characteristics, and the unique impact that wind profiles could have on system operations and planning as the overall penetration of wind power increases.

**Tasks**
The study is planned for completion by mid-2010 and is being structured around five main tasks:

**Task 1: Wind Integration Study Survey**. The project team is conducting a survey of national and international past and current wind integration studies on bulk electric power systems. This includes prior ISO-NE studies, such as *Phases I and II of the Technical Assessment of Onshore and Offshore Wind Generations Potential in New England, the New England Electricity Scenario Analysis*, and actual wind integration experiences in bulk electric power systems.[64] The objective of the survey is to determine the applicability of these studies to future work, such as the specific tools used in the wind integration studies. The information captured during this task will be used to refine the assumptions and deliverables of the remaining tasks of the study.

**Task 2: Technical Requirements for Interconnection.** This task includes the development of specific recommendations for technical requirements for wind generation, such as its ability to reliably withstand low-voltage conditions, provide voltage support to the system, and adjust megawatt output to support the operation of the system. The task also will include data and telemetry requirements, maintenance requirements and scheduling, high wind cutout behavior, and the development of "best practice" methods of the "equivalent load-carrying capability' (ELCC) calculation for global and incremental wind power generation that is used for establishing capacity values.
This task also will investigate and recommend wind power forecasting methods for both the very short-term timeframe, which is useful in real-time operations, and the short to medium-term timeframe, which is useful in unit dispatch and day-ahead unit commitment.

[64] Available on ISO-NE's Web site located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/

**Task 3: Mesoscale Wind Forecasting and Wind Plant Models.**[65] The study will develop an accurate and flexible mesoscale forecasting model for the New England wind resource area (including offshore wind resources) to allow for the simulation of power system and wind generation operations and interactions over the time-scales of interest (e.g., unit commitment, scheduling, load following, and regulation). The model will be designed to output realistic time-series wind data over all terrain types for at least 2004, 2005, and 2006 to quantify the effects of inter-annual variability in wind generation and system-wide load.

**Task 4: Scenario Development and Analysis.** This task will simulate and analyze the impacts of several wind development scenarios in New England on the performance of the electric power system. The scenarios include a base case representing the current system, a scenario for wind development by 2015, and another scenario for 2020 with enough possible wind projects to meet 20 percent of the projected annual use of electric energy. Sensitivity analyses for the 2020 cases will include the impacts of the diversity of the wind portfolio on the performance of the electric power system for scenarios of low diversity, high diversity, and high correlation with system load.

This analysis would lead to recommendations for modifying existing procedures, guidelines, and standards to reliably accommodate the integration of new wind generation. The evaluation also will include a review of ISO-NE's market design with consideration of a high penetration of wind generation and how this scenario could potentially affect system reliability, contribute to inefficient market operation of the bulk electric power system, or a combination of both.

**Task 5: Scenario Simulation and Analysis.** This task will simulate and analyze detailed scenarios to assess the measures needed to successfully integrate a high penetration of wind generation. The investigation will assess the type of forecast needed, such as forecasting lead time, their required accuracy, and implementation issues. The simulations also will evaluate the use of online generation for load-following, regulation, and reserve maintenance and deliverability; the production of power plant air emissions; the effects of carbon costs; and the effects on LMPs. Measures that would facilitate the integration of wind, such as changes to market rules, the addition of electrical storage to the power system, and the use of demand response will also be studied.

**Wind Generator Interconnection Facilitation**

Wind generators that want to interconnect to the ISO system face particular challenges as a result of the differences between wind power and conventional resources. ISO-NE recognizes this and has developed a set of procedures to facilitate wind generator interconnection. ISO-NE staff assist wind generator developers through many of the steps

[65] Mesoscale forecasting is a region-wide meteorological forecasting generally over an area of five to several hundred kilometers.

of the interconnection process and subsequent operations. The steps include the following:

1. Completing all phases of ISO-NE's specific commissioning protocol
2. Meeting requirements for voice communications and data telemetry, depending on the type of markets in which the resource will be participating
3. Designating an entity that has complete control over the resource and that can be contacted at all times during both normal and emergency conditions
4. Submitting real-time self-scheduling information so that it can be accounted for in planning and operations analysis as conducted by ISO-NE
5. Providing other information, such as models, and meeting additional performance requirements, such as voltage control and dispatch

Additionally, wind generators are notified that the interconnection requirements are under review as part of the NEWIS and are therefore, interim requirements that may change once ISO-NE has received and evaluated the NEWIS recommendations.

**Conclusions**

Based upon the outcomes of the NEWIS, ISO-NE plans to evaluate the recommendations from the study and will develop an implementation plan. In the near-term, results derived from the NEWIS - Task 2 - Technical Requirements for Interconnection, would likely result in modifications to ISO-NE's interconnection requirements for wind generators. The balance of the wind integration efforts would be ranked by priority and be completed in accordance to ISO-NE's own project implementation schedule. ISO-NE believes this study would help put the Region in the forefront of integrating significant wind resources into the electricity grid without impairing the reliability and operation of the grid.

## Reliability Assessment Analysis

Table New England 6-1 provides a comparison between the *Reference Case* and the *Scenario Case* for the various types of NERC Summer Margins for the 2018 target assessment year.

**Table New England-6-1: Comparison of 2018 Summer Margins: Reference versus *Scenario Case***

| 2018 Summer Margins ( percent) For: | *Reference Case* | *Scenario Case* |
|---|---|---|
| Region/Sub-Region Target Capacity Margin | NA | NA |
| Region/Sub-Region Target Reserve Margin | NA | NA |
| Existing Certain and Net Firm Transactions | 7.1 | 7.1 |
| Total Potential Resources | 53.2 | 28.0 |
| Adjusted Potential Resources | 20.2 | 27.2 |

Due to the fact that ISO-NE uses a probabilistic methodology[66] to determine resource adequacy needs, both the 2018 Summer Margins for the category *Region/Sub-Region Target Capacity and Reserve Margins* are labeled "Not-Applicable (N/A)", for both the Reference and *Scenario Cases*. Within prior NERC *Long-Term Reliability Assessment* submittals, these two values have

[66] ISO-NE uses the Loss of Load Expectation (LOLE) method for determining New England's annual resource adequacy needs, which in short, accounts for the probabilistic variations in both load and resource availability.

not applied, and unless ISO-NE changes its forward going methodology to determine New England's annual resource adequacy requirements, they will not apply going forward.

The 2018 Summer Reserve Margins for the category *Existing Certain and Net Firm Transactions* shows a 7.1 percent margin for both the *Reference Case* and the *Scenario Case*. This is because both the Reference and *Scenario Case* have the same assumptions for Existing (Certain & Other) Capacity, Future (Planned& Other) Capacity and Capacity Transactions (Imports & Exports).

The 2018 Summer Reserve Margins for the category *Total Potential Resources* shows a 53.2 percent margin for the *Reference Case* and a 28.0 percent margin for the *Scenario Case*. This difference is due to the fact that within both the *Reference Case* and the *Scenario Case,* 100 percent of the identified Conceptual Capacity was added to the *Total Potential Resources* margins. The *Reference Case* Conceptual Capacity (12,462 MW) is 7,808 MW greater than that of the *Scenario Case* Conceptual Capacity (4,654 MW). The *Reference Case Total Potential Resources* margin (53.2 percent) is almost twice as much as that of the *Scenario Case Total Potential Resources* margin (28.0 percent).

The 2018 Summer Reserve Margins for the category *Adjusted Potential Resources* shows a 20.2 percent margin for the *Reference Case* and a 27.2 percent margin for the *Scenario Case*. This difference is due to the fact that within the *Scenario Case,* a 100 percent Confidence Factor (Line 16c) was applied to the Conceptual Capacity, thus adding the total amount of renewable resources (4,654 MW) to the *Adjusted Potential Resources* margins. However, the *Reference Case* only applies a 20 percent Confidence Factor (Line 16c) to the total amount of Conceptual Capacity (12,462 MW), which results in approximately 2,492 MW of resources being applied to the *Adjusted Potential Resources,* which results in a margins of only 20.2 percent.

New England does not have a particular capacity margin requirement; rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion.[67] The capacity needs to meet this criterion are purchased through annual auctions three years in advance of the year of interest. For reference purposes, the annual average percent capacity needed to meet the resource adequacy planning criterion based on a forecast of representative future installed capacity requirements is approximately 15 percent.

Since the primary assumption within the mandate of the Scenario #1 requirement is the an accelerated integration of new renewable resources, this *Scenario Case* assumes that all the new renewable resources (4,654 MW) would be expected to be commercialized within New England and operating as designed during the target assessment year 2018. Thus, in this *Scenario Case* and similar to that within the *Reference Case,* there is maximum reliance on both internal and external capacity resources, in the year 2018, to be available to deliver their capacity and energy as contractually bound to satisfy their obligations under the FCM.

[67]To develop installed capacity requirements to meet the once in 10 years disconnection of firm load resource planning reliability criterion, ISO New England takes into account the random behavior of load and resources in a power system, and the potential load and capacity relief obtainable through the use of various ISO-NE Operating Procedures.

As stated above, there is maximum reliance on external capacity resources, in the year 2018, to be available to deliver their capacity and energy as contractually bound to satisfy their obligations under the FCM.

The one exception to the statement above concerns the wind resources that are targeted for commercialization within Aroostook County, Maine. In more detail for the year 2018, the *Reference Case* Conceptual Wind Capacity was assumed to be 2,180 MW versus 3,380 MW in the 2009 *Scenario Case*, a difference of 1,200 MW. This large difference in new wind project assumptions are the five (5) proposed wind projects (totaling 1,200 MW of nameplate capacity) proposed for Aroostook County, Maine. Currently, that part of the bulk electrical system is operated by Northern Maine Independent System Administrator (NMISA), which is not part of the ISO-NE's Regional Balancing Authority, so therefore those projects are currently not included within the ISO-NE Generation Interconnection Queue.[68] However, in keeping with the mandate of the Scenario #1 requirement, for the *Scenario Case* it was assumed that these new, renewable wind projects were assumed to materialize and due to their significant size and the future need to satisfy Regional renewable portfolio standards (RPS), those projects would eventually be (by 2018) incorporated into either the New England (under ISO-NE Balancing Authority) or New Brunswick (NBSO Balancing Authority) power grids via new bulk transmission interconnections.

No detailed resource adequacy or (LOLE-based) reliability studies were performed to gauge the impact on system reliability from the set of assumptions contained within the mandates of the Scenario #1 requirement.

As noted above, since no detailed resource adequacy or (LOLE-based) reliability studies were performed to gauge the impact on system reliability from the set of assumptions contained within the mandate for the Scenario #1 requirements, no LOLE comparison can be made between the *Reference Case* and the *Scenario Case*..

Since the projected seasonal peak demands are the same within both the Reference and *Scenario Cases*, a higher peak demand in the range of the 90/10 forecast would probably require the use of Emergency Operating Procedures (EOPs), should supply and demand-side resources be short of serving increased 90/10 demand levels. ISO-NE currently has approximately 4,000 MW of load and capacity relief available within various EOPs. It is assumed that by 2018, that amount of load and capacity relief would be significantly increased due to the upcoming implementation of new *"smart-grid"* technologies.

---

[68] As of the March 15, 2009 ISO-NE Generator Interconnection Queue, proposed projects were sorted into two categories: Category #1 = *Active – Administered Transmission System, which are Interconnection Requests to the Administered Transmission System, Generation and Elective Transmission Upgrade Requests, and Requests for Transmission Service* (These are FERC regulated projects falling under the ISO-NE Open Access Transmission Tariff (OATT) - Schedules 22 & 23), and Category #2 = *Active – Affected System – Interconnection Requests for which the Administered Transmission System is an Affected System, Generation Requests* (These projects are either FERC regulated projects that not fall under the ISO-NE Open Access Transmission Tariff (OATT) Schedules 22 & 23, due to their interconnection location on the local or distribution system or these projects may be non-FERC regulated projects on neighboring systems, that may however, impact the reliability of ISO-NE's bulk transmission system, and thus, require transmission interconnection studies by ISO-NE.

ISO-NE is not aware of any future unit retirements, and does not make projections about potential retirements, although the potential for retirements may be considered part of system design. This unit retirement assumption (of no assumptions) is the same within both the Reference and *Scenario Cases*. As noted earlier, nuclear plant relicensing and *once-through* cooling issues are probably the only major open issues at this time.

The assumption on the deliverability of resources is the same within both the *Reference Case* and the *Scenario Case*. ISO-NE currently addresses generation deliverability through a combination of transmission reliability and resource adequacy analyses. Detailed transmission reliability analyses of sub-areas of the New England bulk power system confirm that reliability requirements can be met with the existing combination of transmission and generation. Multi-area probabilistic analyses are conducted to verify that inter-sub-area constraints do not compromise resource adequacy. The ongoing transmission-planning efforts associated with the New England Regional System Plan (RSP) support compliance with the NERC Transmission Planning requirements and assure that the transmission system is planned to sufficiently integrate generation with load.

As a notable generic exception to the statement above, there currently exists several bulk transmission interfaces on the New England system, which are currently impacted by thermal, stability, and voltage limitations. These transmission interfaces limit the free flow of power across the system. Assuming the mandate of an accelerated integration of renewable resources as mandated by the Scenario #1 requirement, it would be a safe assumption for New England that a majority of these new renewable resource that would be expected to be commercialized and operating during the target assessment year 2018, and thus would require a some build-out of the exiting transmission system within the Region to accommodate the influx of 4,654 MW of new renewable capacity. Depending on where these projects are physically located and thus "electrically-located," they may either be on the "right-side" or "wrong-side" of an existing transmission interface, thus either helping to dampen the constraining effects of the transmission interface or exacerbating it. Thus, aside from the standard supply-side resource interconnection process for which either a minimum transmission interconnection standard or a maximum[69] (output) transmission interconnection standard could be applied, some amount of additional transmission expansion would definitely be required to ensure the unconstrained delivery of this new renewable power throughout the existing ISO-NE system.

Under the *Scenario Case*, over 4,654 MW of new, renewable resources is assumed commercialized for the target year 2018. Because over one-third of the exiting capacity within New England is fossil-fueled, natural gas-fired technologies (SC & CC), the integration of 4,654 MW of renewable resources would work to diversify a power generation fleet that is already over-reliant on gas-fired generation. Variable generation like wind has no fuel source, and the remaining renewables, biomass, landfill gas, small hydro-electric, and fuel cells[70] would use power plant fuels that are considered renewable in nature, thus providing resource and fuel diversity to the Regional fleet.

[69] Currently referred to within the FCM as the *Capacity Capability Interconnection Standard (CCIS).*

[70] However, fuel cells would need to be fueled by pipeline quality natural gas, and as such, would be an incremental (although minimal) gas load upon existing pipelines and/or gas LDCs.

However, it still should be noted that a significant loss of natural gas supply to the Region could significantly impact a portion of the gas-fired fleet, since the majority of gas-fired power plants within the Region rely on both interruptible gas supply and transportation agreements to satisfy a large portion of their fuel portfolios. This situation could be more problematic from a transmission-import constrained load zone perspective, where native gas-fired generation must be kept online to satisfy the own-load transmission security requirements of the subregion. However, 4,654 MW of new renewable resources would work towards diminishing such risks, but possibly not eliminating them.

### Region Description

*ISO New England Inc. is a Regional Transmission Organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It is responsible for the reliable day–to-day operation of New England's bulk power generation and transmission system, and also administers the Region's wholesale electricity markets and manages the comprehensive planning of the Regional bulk power system. The New England Regional electric power system serves 14 million people living in a 68,000 square-mile area. New England is a summer-peaking electric system, which set an all-time peak demand of 28,130 MW, which occurred on August 2, 2006.*

## New York

### Executive Summary

The NYISO is currently studying the integration of 8,000 megawatts (MW) of wind-generating resources into the New York bulk electric transmission grid in the year 2018. The final report is currently scheduled to be presented to our Market Participants, finalized and released in the fourth quarter of 2009. The energy that is projected to be generated with the addition of these wind plants is assumed to comprise approximately 12 percent of the projected New York Control Area energy use in 2018. For that same year, another 5.4 percent of the energy need is assumed to be provided by Energy Efficiency. Combined, wind resources and Energy Efficiency; represent approximately 16-18 percent of the total NYISO forecasted energy needs for 2018.

Our preliminary analysis indicates that some of the wind energy could be constrained and not deliverable without transmission upgrades. This results in a reduction of the wind energy to meet the projected 2018 energy use. When combined with the assumed 5.4 percent level of Energy Efficiency, these resources then would likely represent approximately 15-17 percent of the 2018 forecasted energy need.

This level of wind penetration would likely result in increased operating challenges on a day-to-day basis due to the variability of wind in real-time and transmission congestion in some areas of the transmission system, possibly where it is currently not encountered.

The NYISO has in place five-minute nominal dispatch cycles, real-time and day-ahead forecasting, which also includes wind resources and the integration of wind into economic dispatch. The NYISO cautions that the results of this study may not apply to much higher levels of wind plant penetration, e.g. 20 percent and 30 percent of total energy. Such higher levels would require further study.

It is important to note that this document consists of the results of an ongoing study, the final results of which will occur after the publication of this scenario. Therefore any preliminary representations contained herein, reflect the status of that study as of August 7, 2009, and the final results are subject to change.

### Introduction

The *Reference Case* used for comparison with this Scenario is the NYISO 2009 *Long-Term Reliability Assessment* report. The 2009 *Reference Case* is based upon econometric load forecasts from the NYISO 2009 Load and Capacity Data Report ("Gold Book")[71]. The *Scenario Case* was developed from the NYISO's 2009 RNA Report[72]. The underlying data for the *Reference Case* was initially based upon econometric load forecasts from the 2008 Load and Capacity Data Report with revisions made in August 2008 to account for changes due to the Energy Efficiency Portfolio Standard (EEPS) and to include new information developed after the publication of the 2008 Gold Book and prior to the start of the 2009 RNA study.

[71] 2009 Load and Capacity Data Report, http://www.nyiso.com/public/services/planning/planning_data_reference_documents.jsp
[72] 2009 Reliability Needs Assessment, Final Report January 2013. http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/RNA_2009_Final_1_13_09.pdf

The power flow analysis and simulations for 8,000 MW of wind were only conducted for the study year 2018. The purpose of the study is to determine the areas of the transmission system and the extent that wind plants would be constrained as well as how system variability would be impacted by wind.

### Demand

The NYISO used its August 2008 demand forecast for the *Scenario Case*. It includes the impact of new Energy Efficiency/conservation initiatives being implemented by the State of New York as part of the Energy Efficiency Portfolio Standard. The economic assumptions include higher economic growth than in the 2009 *Long-Term Reliability Assessment* load forecast, which was prepared after the current recession commenced. The weather assumptions are the same as those used in the 2009 *Long-Term Reliability Assessment* load forecast.

The 2009 summer peak demand reported in the 2009 *Long-Term Reliability Assessment* was forecasted to be 33,452 MW. For the same year, the scenario's summer peak demand forecast was 34,059 MW. The 2018 summer peak forecast in the 2009 *Long-Term Reliability Assessment* is 35,450 MW, a growth of 1,998 MW over nine years. The scenario's peak forecast for the same year is 35,658 MW, a growth of 1,599 MW. The annual average growth rate summer peak demand for the 2009 *Long-Term Reliability Assessment* is 0.65 percent. For the same period, the summer peak demand growth rate of the scenario is 0.51 percent.

### Generation

Capacity resource data in the base *Scenario Case* are from the 2009 RNA report. These include generation resources listed in the 2008 Gold Book, 2,084 MW of Special Case Resources, and those resources that met specific screening requirements for inclusion while the *Reference Case* used the 2009 Gold Book data Also, the *Reference Case* includes assumptions for Future Capacity additions and Conceptual additions that were different from the Scenario study conditions. The resulting differences total a reduction of 1,333 MW for the *Scenario Case* study year of 2018 vs. the *Reference Case*. Capacity resources of 42,536 MW were included in the *Scenario Case* versus the 43,869 MW reported in the *Reference Case*.

For the *Scenario Case* study, 8,000 MW of wind resources were added, all in the year 2018. The figure below presents the simulated output of the 8,000 MW of wind assuming no transmission constraints. The trend component, or green line is the 720 hourly moving average or monthly moving average. It demonstrates how the wind plant output varies seasonably.

The 8,000 MW of wind included in this study represents nearly all of the wind projects listed in the NYISO Interconnection Queue as of the ignition of the study.[73] These projects have not met any milestones other than having submitted a request to be interconnected to the NYISO transmission system.

[73] The interconnection process is a formal process defined by NYISO's tariffs by which the NYISO evaluates transmission and generation projects, submitted by Market Participants, developers, and other qualified organizations to determine their impact on system reliability.

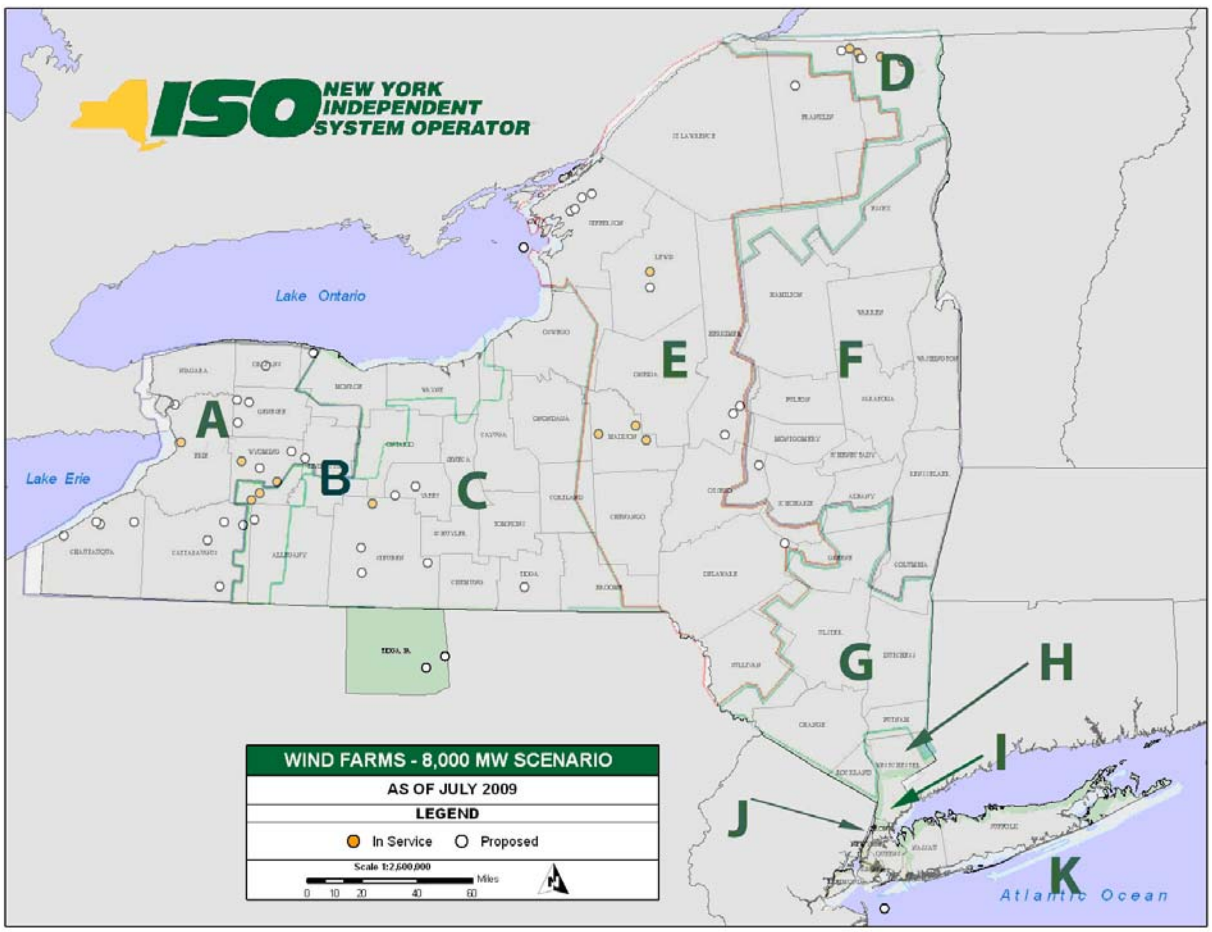
### Capacity Transactions on Peak

The *Scenario Case* external capacity import transactions are also based on the 2009 RNA report. These transactions total 3,280 MW as compared to the 3,160 MW reported in the *Reference Case*. This small difference of 120 MW had no measurable impact on the system reliability for this study.

### Transmission

The transmission system topology for the purposes of this study was unchanged from the *Reference Case*, except for the transmission facilities that were required to connect the wind plants to the transmission system. The map below displays the locations of existing wind plants, as well as the locations of the additional wind plants that would be needed to meet the 8,000 MW of installed wind studied in this scenario.

For the *Scenario Case* study, 8,000 MW of wind resources were added, all in the year 2018. Approximately 1,400 MW were located downstate in New York City and Long Island (Zones J & K) while the remaining resources were located upstate (predominately in Zones A-E, as set forth in the map below).



Power flow analysis was conducted to identify critical contingencies, which were then modeled in the GridView market simulation tool. The GridView tool simulates day-ahead commitment and real-time dispatch. The simulations were used to determine how wind resources would be impacted by transmission constraints and what resource would be displaced by wind generation.

The simulations determined that some of the potential wind energy would not be deliverable, and that the primary transmission constraints would be in localized areas. The wind generation that was deliverable, would primarily displace gas-fired generation, followed by the displacement of oil-fired generation, and, thereafter, a small amount of coal-fired generation. The map on the next page shows those locations in the New York bulk power system where transmission constraints are likely.

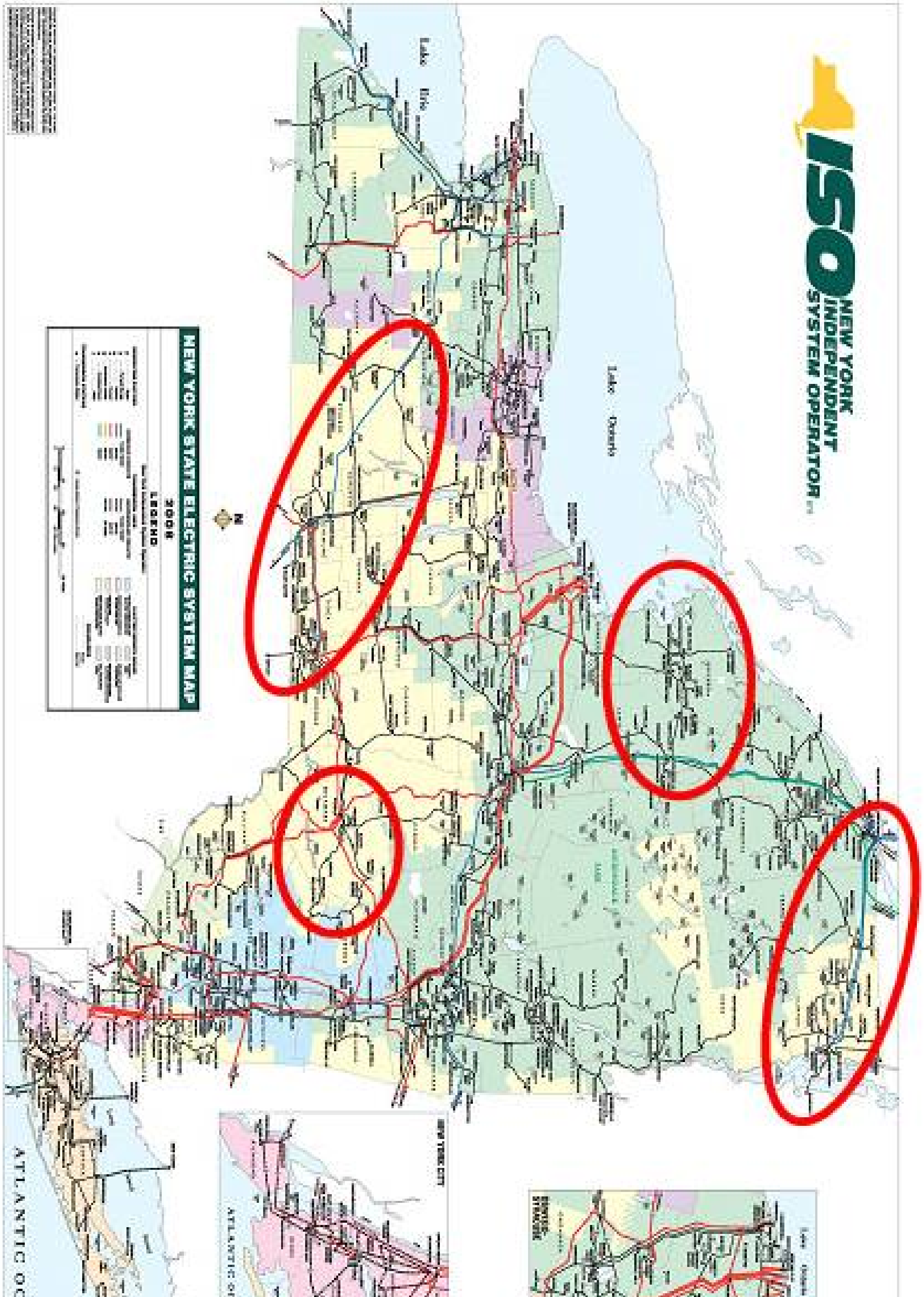
### Operational Issues

From an operational perspective, power systems are dynamic, and are affected by factors that change each second, minute, hour, day, season and year. In each and every time frame of operation, it is essential that balance be maintained between the load on the system and the available generation. In the very short time frames (seconds-to-minute), bulk power system reliability is almost entirely maintained by automatic equipment and control systems, such as automatic generation control (AGC). In the intermediate to longer time frames, system operators and operational planners are the primary keys to maintaining system reliability. The key metric driving operational decisions in all time frames is the amount of expected load and its variability. The magnitude of these challenges increases with the significant addition of wind-generating resources.

Due to its intermittent nature, wind has more in common with the load than it does with conventional generation. Therefore, the primary metric of interest in assessing the impact of wind on system operations is the net load, which is defined as the load minus wind. It is the net load that the non-intermittent or conventional generation must be able to respond. This scenario will evaluate the impact of 8,000 MW of wind-generation resources on system variability. This analysis will have the potential for determining any need for increases or decreases in system regulating resources and ramping within an hour, between hours, and across multiple hours.

System variability as measured by sigma or the standard deviation of the change in net load is not constant across all hours. It tends to be highest in the higher load months, which is the summer capability period for the New York Control Area. Load also varies by time of day, with system load variability generally highest during the morning ramp up and the evening ramp down. Simulation of 8,000 MW of wind with 2018 hourly load forecast will indicate that the sigma of the net-load in the five to ten minute time frame.

The 8,000 MW of wind being studied would also result in determining the within hour and hour-to-hour changes that drive the systems load following and ramping needs.


NEW YORK INDEPENDENT SYSTEM OPERATOR
NEW YORK STATE ELECTRIC SYSTEM MAP
2008
LEGEND
Lake Ontario
Lake Erie
ATLANTIC OCEAN

It will be important to determine if, at 8,000 MW of wind-generation, the NYISO would need conventional generation to be more responsive in order to follow the increased power system variability. Overall, the NYISO preliminarily believes that its day-ahead scheduling system and nominal five-minute dispatch and scheduling cycles would be capable of reliably integrating the levels of wind-generation studied. It would be the rare extreme events, e.g., the unanticipated drop off of a large amount of wind generation over very short period of time that could pose significant reliability challenges under the condition studied but these events can be addressed through heightened operational awareness when the potential for such events exist.

The NYISO study will look at the issues related to the integration of intermittent resources, such as whether minimum generation levels required for conventional generation would impact the dispatch of wind resources. Also, the year-to-year variability in energy output from intermittent resources should be investigated further. The NYISO's experience with existing wind-generation resources and the experience of other systems have already resulted in several initiatives to reliably integrate wind and respond to such events. To date the NYISO has:

- Established a centralized wind forecasting system;
- Become the first grid operator to fully integrate wind resources with economic dispatch of electricity; and
- Developed new market rules to expand the use of new energy storage systems that complement wind generation.

In conclusion, the levels of wind-generating resources studied in this scenario would likely pose increased transmission system operating challenges on a day-to-day basis.

### Reliability Assessment Analysis

The following table compares the *Reference Case* Reserve Margins vs. the *Scenario Case* Reserve Margins (with and without 8,000 MW of wind for the year 2018).

**Table New York-1: Reserve Margins *Reference Case* vs. *Scenario Case* (2018)**

| Resources | *Reference Case* | *Scenario Case* w/o Wind | *Scenario Case* w/wind |
|---|---|---|---|
| Deliverable | 22.8 percent | 28.1 percent | 49.1 percent |
| Total Potential | 33.5 percent | 29.3 percent | 51.9 percent |

Historically, the required Installed Reserve Margin, based upon Loss of Load Expectation analysis, for the New York Control Area has ranged from 15 percent to 18 percent[74]. Thus the projected Reserve Margins for 2018 as determined by the 2009 *Reference Case* and *Scenario Case Long-Term Reliability Assessment* reports are well above the historical expected requirement.

There are two main differences between the assumptions made between the Reference and *Scenario Case*s, the first being the Demand Forecast. The Energy Efficiency forecast for the

[74] See Installed Reserve Margin studies as published on the New York State Reliability Council website: http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

*Scenario Case* was about 325 MW higher than the *Reference Case* while the overall peak demand forecast was about 120 MW higher than the *Reference Case*. The primary driver for these differences was the economic downturn experienced at the end of 2008 and continuing into 2009. The *Reference Case* incorporated this new economic information while the Scenario did not.

The second assumption difference was in the capacity resources recorded throughout the study period. The *Reference Case* included resources from the 2009 Gold Book that had met specific milestones as Future Planned resources. Other resources that had not met these milestones, particularly those resources with anticipated in-service dates well into the 10 year study period, were included in the Conceptual category. The *Scenario Case* included those same resources that met the specific milestones but none that were categorized as Conceptual.
Since the Reserve Margin for 2018 is well above the historical requirement prior to the study addition of 8000 MW of wind, the amount of internal and external resources required to meet criteria is not affected by the level of additional wind resources studied. Also, the wind resources being studied will not replace any existing resources in the New York Control Area. They may, however, displace the dispatching of existing higher-cost generation.

From a resource adequacy perspective, the *Scenario Case* represents a much more reliable system – nominally a 50 percent reserve margin vs. a nominally 30 percent reserve margin. Operationally though, wind presents unique operational characteristics due to its variability, as described elsewhere in this report.

The peak demand forecast would need to increase by nearly 25 percent before the Reserve Margin is reduced to 18 percent, the maximum historical value required by the New York Control Area.

Both the *Reference Case* and the *Scenario Case* assumed the same retirements (1093 total MW). There was no impact on reliability due to these retirements.

There is no difference in deliverability of resources between the *Scenario Case* and the *Reference Case* as measured by LOLE. In fact, the beginning assumption is that additional resources would reduce LOLE. As described above in the transmission study, some amount of the wind capacity is “bottled” but that portion which is deliverable from an energy perspective displaces higher cost generation which is primarily gas followed by oil and then coal

As part of its interconnection process all wind plants are subjected to voltage testing. If issues are identified, the developer is required to install system upgrade facilities such as capacitor banks and SVC to address any issues identified in the interconnection study. As noted above, the NYISO has modified its market rules to accommodate new types of technologies such as fly wheels in order for them to participate in the regulation market which one of the NYISO’s ancillary services. In addition, the NYISO can increase its procurement of regulation MW if needed to meet reliability criteria.

As described throughout this document there have been a number changes to the NYISO’s market structure to address the issues with integrating significant amounts of wind and other renewable generation. The NYISO would address changes in ancillary service requirements, if required, to implement 8,000 MW of wind.

The addition of 8000 MW wind in 2018 would increase fuel diversity in New York. The wind resources would displace fossil-fired generation, which could have a positive benefit to New York when considering potential fuel supply vulnerability issues.

### 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 all-time peak load of 33,939 MW set in 2006. (http://www.nyiso.com).*

## Ontario

### Introduction

The 2009 NERC Long Term Reliability Assessment for Ontario is the *Reference Case* against which this *Scenario Case* is compared.

The *Reference Case* is based on a working revision to the Ontario Power Authority's[75] 2007 Integrated Power System Plan (IPSP); which serves as the roadmap to achieving the Ontario government's long-term electricity goals, including a target of 22,000 MW of renewable resources and conservation efforts by the year 2025. The *Scenario Case* is based on an alternate working revision to the OPA's 2007 IPSP and includes additional renewable wind generation over the *Reference Case*. Based on the already aggressive target for renewable generation under the *Reference Case*, the *Scenario Case* supply mix represents only a small incremental increase of renewable resources in terms of incremental annual energy. This incremental energy (*Scenario Case* over *Reference Case*) from renewable generation amounts to 2.6 percent of 2008 Ontario energy demand. There is no incremental energy contribution from conservation initiatives in the *Scenario Case*.

The *Scenario Case* demand forecast for the 2009 to 2018 period is the same as the *Reference Case* demand forecast, and assumes that all of the OPA's planned conservation initiatives, as well as contribution from planned distributed generation resources, are realized on time. Also consistent with the *Reference Case* is that by the end 2014, all of Ontario's coal-fired generation is to be retired, and a significant number of nuclear units are scheduled for retirement or refurbishment. The main assumption difference for the *Scenario Case* is the incremental addition of over 2,500 MW installed capacity (about 1,000 MW effective capacity) by the year 2017. Of this 2,500 MW, 1,500 MW is installed wind capacity and 1,000 MW is gas-fired capacity.

Over the period 2009 to 2018, the Ontario system is expected to operate reliably and meet required reserve margins under *Scenario Case* demand, supply and transmission assumptions. In fact, reserve above required margins over the 2012-2018 timeframe are higher than those in the *Reference Case*, as only incremental resources are added; with no reduction in generation capacity or change from the *Reference Case* generation retirement schedule. Demand forecast stays the same for both scenarios. Incremental resources included in the *Scenario Case* are in place to offset approximately 1,200 MW less nuclear generation capacity (*Scenario Case* vs. *Reference Case*) scheduled to come in-service beyond the 2018 study timeframe (as per OPA's working revisions to the 2007 IPSP).

Additional transmission infrastructure is required to facilitate the incremental 2,500 MW of installed generation capacity by the year 2017. Maintaining the reliable operation of the system under the *Scenario Case* would require careful management of the supply-demand balance under low load conditions. In addition, the increasing contribution of renewable and embedded (distributed) generation would require enhanced procedures and processes in both planning and operation of the Ontario system. The main considerations and initiatives identified under the

[75] Established in 2005, the Ontario Power Authority (OPA) is the electricity system planner for the province of Ontario.

operability section of the *Reference Case* assessment are expected to play an increasingly vital role in the operation of the system envisioned in the *Scenario Case*.

### Demand

The *Scenario Case* demand forecast for the period 2009 to 2018 is the same as the *Reference Case* demand forecast used in the 2009 NERC *Long-Term Reliability Assessment*. This includes all weather, economic, conservation and embedded generation forecast assumptions. Overall, this year's demand forecast has an average annual growth rate of -0.7 percent over the ten year period. This negative growth in demand is based on the expected economic/industrial restructuring following the current economic recession, as well as the expected impact of conservation and embedded (distributed) generation.

### Generation

Capacity resources listed under the Existing and Future/Planned categories are identical in both the *Reference* and *Scenario Cases*. Generation resource assumptions differ only under the Conceptual/Proposed category; where under the *Scenario Case*, incremental installed wind generation appears in 2012, and grows to 1,500 MW by 2017, while incremental gas-fired generation (approximately 1,000 MW) comes in-service in 2015. The *Scenario Case* does not include any advanced or additional generation retirements, or changes in schedule to any Future or Conceptual resources that are included in the *Reference Case*. As a result, overall capacity over the 2012-2018 timeframe is higher in the *Scenario Case* versus the *Reference Case*.

Consistent with *Reference Case* assumptions, eleven percent of the installed wind capacity is assumed to be available at the time of summer peak, and thirty percent is assumed to be available at the time of winter peak for years 2009 and 2010. These values represent IESO capacity values for wind generation and fall under IESO's operational planning timeframe (18-Month forecast). From 2011 onwards, the OPA's summer peak wind capacity value of twenty percent of installed capacity is used[76] (the winter capacity value of thirty percent is retained over this time period).

Planned and Proposed capacity resources for the *Scenario Case* are selected based on an alternate working revision to the Ontario Power Authority's 2007 Integrated Power System Plan. The OPA's statutory objects require it to, among other things, ensure adequate, reliable and secure electricity supply and resources in Ontario and to conduct independent planning for electricity generation, demand management, conservation and transmission.

One of the responsibilities of the OPA is to develop a 20-year IPSP and to submit the IPSP to the Ontario Energy Board for its review and approval. The IPSP is to be updated every three years. The IPSP must follow any directives issued by Ontario's Minister of Energy and Infrastructure relating to the government's electricity goals. In addition, the OPA must develop appropriate procurement processes for managing electricity supply, transmission capacity and demand measures and must apply to the Ontario Energy Board for approval of the IPSP's proposed procurement processes.

[76]Calculation of the OPA's wind capacity contribution value can be found at the following link: http://www.powerauthority.on.ca/Storage/53/4871_D-5-1_Att_4_corrected_071019.pdf

Ontario's first IPSP was submitted to the Ontario Energy Board for review in August 2007. It covers a period of twenty years, complies with the goals and requirements set out by the government of Ontario, and proposes a procurement process for managing electricity supply, transmission capacity and demand measures. In the fall of 2008, Ontario's Minister of Energy and Infrastructure directed the OPA to revisit the IPSP with the aim of establishing new targets for the amount and diversity of renewable energy sources, conservation programs and other initiatives. Two working revisions of the IPSP were provided as inputs for the *Reference Case* and *Scenario Case* assessments respectively. Planned and Proposed resources are based on the most recently available data associated with the *Scenario Case* OPA working revision.

### Capacity Transactions on Peak

At present, there are no Firm, Non-Firm, Expected or Provisional purchases or sales to or from other Regions. This assumption is consistent to the capacity transaction assumptions used in the *Reference Case*.

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

Integration of incremental wind and gas-fired generation envisioned under the *Scenario Case* would require a greater number of the new transmission projects identified in the *Reference Case* to be constructed. At the Proposed/Conceptual level, a large portion of the additional wind and all of the gas-fired generation under the *Scenario Case* would be located in Ontario's West transmission zone. As a result, it is expected that construction of the new line(s) west of London would need to be suitable for 500kV operation to incorporate the additional generation. Adopting a 500kV standard for the new transmission lines would also require 500/230kV auto-transformers to be installed at Lambton TS and possibly at Chatham TS.

Similarly, with more incremental renewable resources developed, a greater number of the enabler transmission lines identified in the *Reference Case* would need to be constructed to accommodate the additional resources identified in the *Scenario Case*.

### Operational Issues

Operational issues identified in the *Reference Case* such as Surplus Baseload Generation (SBG) during minimum load periods would require increasingly careful planning and management under *Scenario Case* assumptions.

Similar to the *Reference Case*, the implementation of a centralized wind forecast system is a likely requirement for the system to be able to handle the variability of wind generation – this requirement is heightened in the *Scenario Case*. At the same time, the need for reliable and maneuverable generation for load following purposes also increases with greater penetration of variable generation. In the *Scenario Case*, incremental wind generation is accompanied by approximately 1,000 MW of gas-fired generation that is expected to fall under the category of peaking generation. The operational flexibility associated with this proposed gas-fired generation is expected to enhance the effective management of increased variable generation by providing ramp capability, and the ability to provide operating reserve.

## Reliability Assessment Analysis

As described earlier in this assessment, the *Scenario Case* has the exact same generation portfolio from 2009-2011, and only additional generation capacity from 2012-2018, when compared to the *Reference Case*. In addition, the demand forecast is the same for both cases. As a result, projected capacity margins for the *Scenario Case* are the same over the first three years of the study, and higher over the remaining years when compared to the *Reference Case*. Ontario reserve margin requirements are satisfied by Existing, Planned and Proposed internal generation resources described in the *Scenario Case* over the entire assessment period.

No new assumptions were made when evaluating reserve margin criteria for the *Scenario Case*, and at present, there have been no additional resource adequacy studies performed to evaluate required reserve margins under *Scenario Case* assumptions.

The deliverability of additional resources in the *Scenario Case* would be driven primarily by the implementation of transmission enhancements described in the *Transmission* section.

An additional 1,500 MW of wind resources by 2017 are considered for the *Scenario Case* over the *Reference Case.* The numerous shunt capacitors to be installed throughout the network together with the 350 MVAr SVCs to be installed at Nanticoke GS 500 kV bus and Detweiler TS 230 kV bus (under *Reference Case*) are assessed as being sufficient to provide dynamic reactive support during post contingency situations.

Minimum load conditions occur when baseload generation is greater than the market demand. This is expected to occur more often during low demand conditions with the addition of more intermittent renewable resources. The magnitude, frequency and duration of these conditions may be exacerbated in the *Scenario Case.* The IESO is currently engaging stakeholders on the management of minimum load conditions specifically through the development of policies regarding the sharing of dispatch between nuclear, baseload hydroelectric, and other baseload resources such as wind, biomass and self-scheduling generation.

As the amount of variable wind resources in the system increases, peaking gas generation resources are anticipated to be added as well. This addition of peaking gas, along with other maneuverable generation in existence or planned in the *Reference Case*, should provide sufficient commitment and ramping capability to offset increased variability from the incremental wind in the *Scenario Case.*

Over the ten year horizon, increased reliance is being placed on natural gas-fired generation as coal is phased out. Overall gas supply adequacy and gas transmission issues have been examined extensively since 2005 by the Ontario Gas Electric Interface Working Group. Canadian and Ontario pipeline and gas-distribution operators have implemented various tariff changes to enhance gas usage flexibility and improve firmness of supply available to generators. The Working Group has procedures in place for the continued monitoring of operations and identification and resolution of issues to mitigate fuel vulnerability. The *Scenario Case* is not expected to increase fuel supply vulnerability significantly over the *Reference Case.*

## Region Description

*The province of Ontario covers an area of 1,000,000 square kilometers (415,000 square miles) with a population of 12 million. The Independent Electricity System Operator (IESO) directs the operations of the IESO-controlled grid (ICG) and administers the electricity market in Ontario. The ICG experiences its peak demand during the summer, although winter peaks still remain strong.*

# Québec

## Executive Summary

For Québec Area, NERC 2009 *Long-Term Reliability Assessment Reference Case* is identical to the *Scenario Case* with renewable resources integration. This is because all future resources to be placed in service are renewable (Hydro, Wind and Biomass Power).

## Introduction

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

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

All electricity generation methods have environmental impacts. One way to limit these impacts is to control demand. HQ works closely with the "*Agence de l'efficacité énergétique*" (Energy Efficiency Agency) to encourage customers to use energy more wisely, as part of our Energy Efficiency Plan.[77]

Hydro-Québec reiterates its commitment to sustainable development by focusing on renewable energy. New resources to be put on line would be renewable resources (wind, biomass and hydropower). Therefore, the *Scenario Case* (Renewable resources integration scenario) is identical to the *NERC Long-Term Reliability Assessment 2009 Reference Case*.

Compared to the *NERC Long-Term Reliability Assessment 2008 Reference Case* there are 5 new items in this assessment:

- Call for tenders A/O 2009-02 for two blocks of 250 MW of wind-generated capacity, one resulting from First nations projects and one resulting from community projects.[78]
- Call for tenders A/O 2009-01 for 125 MW of biomass cogeneration.[79]

---

[77] With a focus on sustainable development, the Agence de l'efficacité énergétique's mission is to promote Energy Efficiency and the development of new technologies for all forms of energy in every sector of activity. Its English web site address is: http://www.aee.gouv.qc.ca/en/home/.

[78] An English description of this call for tenders can be found at this web address: http://www.hydroquebec.com/distribution/en/marchequebecois/ao-200902/index.html

[79] An English description of the call for tenders can be found at this web address: http://www.hydroquebec.com/distribution/en/marchequebecois/ao-200901/index.html;

- Power Purchase Program for small hydropower projects of 50 MW or less for a total of 150 MW. To be released later in 2009;
- Wind project (280 MW) by Hydro-Québec Production;
- New Energy Efficiency programs evaluated at 1,150 MW.

The last Québec Area Comprehensive Review of Resources Adequacy, approved by the Reliability Coordinating Committee of the NPCC on March 11, 2009, indicates 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).[80]

***Significant assumptions***

NERC requires each Balancing Authority Area to produce a scenario which accommodates a minimum of 15 percent of total energy from renewable resources, with no more than 5 percent made up from Energy Efficiency programs. The base year for calculating the 15 percent benchmark is 2008. These renewable resources should be put in service within 10 years.

In 2008, the internal demand in Québec was 188,918 GWh. Fifteen percent of this internal demand represents 29,106 GWh. Therefore, the Area has to integrate almost 30 TWh per year of renewable resources to its electric system within 10 years.

The Québec Balancing Authority Area already has 532 MW of wind power generation and during the next ten years 3,450 MW of additional wind power generation would come on line. In all its previous reliability studies, Québec's wind generation was derated to zero. In this assessment, this is still the case. By the end of 2009, Hydro-Québec Distribution will present its analysis regarding the Québec wind farms' capacity factor on peak to the Québec Energy Board. A capacity factor of 30 percent is expected to used in future studies.

## Demand

There is no difference between the load forecasts used in this 15 percent renewable resource Integration *Scenario Case* and the *Reference Case* of the NERC *2009 Long-Term Reliability Assessment.*

The observed peak load for winter 2008/2009 was 37,230 MW and was reached on January 16th, 2009 at 8h00 AM EST. This is a new all-time record for internal demand in Québec. Demand was approximately 850 MW higher than the forecast peak for winter. This is due to a short but sharp cold spell, culminating on January 16th. Montréal temperature at the time of peak was -26°C (-11°F) and wind speed was about 11 km/hour (7 mph). The rest of winter 2008/2009 experienced close to normal temperatures and internal demand values were also close to projected values. The available internal capacity (with due regard to imports, exports and

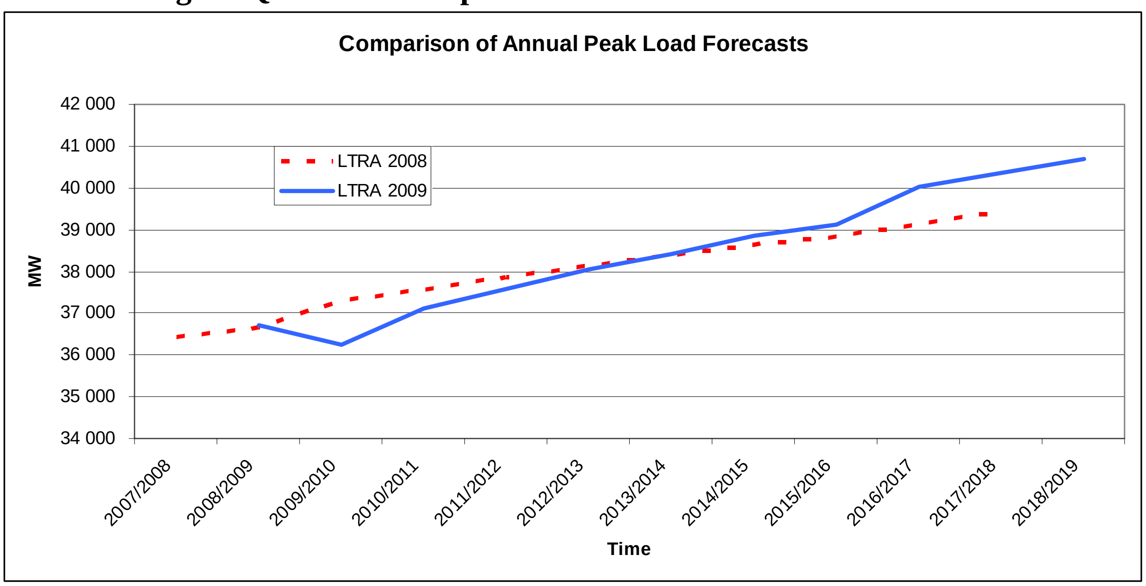
[80] This Comprehensive Review is available on the NPCC web site: http://www.npcc.org/documents/reviews/Resource.aspx.

demand response programs) was sufficient to balance out the load with all operating reserves well within limits.
Climatic uncertainty is modeled by recreating each hour of the 36 years period (1971 through 2006) under the current load forecast conditions. Moreover, each year of historic data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend for example. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of those 252 scenarios. A high case demand scenario is also produced. Economic parameters are set higher and the same method than the base case is reproduced. For the first year of forecasting, the high case scenario is 2 to 3 percent higher than the base case scenario. Modeling uncertainty is represented through load multipliers covering two standard deviations. Each load multiplier has a certain probability of occurrence. Given the global uncertainty and assuming a normal distribution, the peak demand standard deviation is 1,710 MW for the 2009/10 Winter Operating Period.

The average annual *2009 Long-Term Reliability Assessment* Québec load forecast growth, from the winter peak period 2008/2009 to 2018/2019, is 1.04 percent. Hydro-Québec Distribution is the only Load Serving Entity in Québec. Its load forecast is conducted for the Québec Balancing Authority Area represented as a single entity and there is no demand aggregating.

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

**Figure Québec-1: Comparison of Annual Peak Load Forecasts**




Under Hydro-Québec's Energy Efficiency Plan (EEP), the goal for 2010 is 5.8 TWh in recurring energy savings. The target for 2015 incorporating all of initiatives is 11 TWh/year. The EEP focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers.

The programs and tools for promoting energy saving are the following:[81]

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

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

For business customers – large power users

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

## Generation

In Québec, all the resources to be put on line are renewable resources (wind power, biomass and hydroelectric power). Therefore, the renewable resources integration scenario is identical to the NERC *Long-Term Reliability Assessment 2009* assessment.

In order to go ahead, our hydroelectric development projects must fulfill three criteria. They must be:

1. profitable;
2. environmentally acceptable;
3. favorably received by the host communities.

Hydropower facilities with reservoirs offer unique operational flexibility in that they can respond immediately to fluctuating demand for electricity. Hydropower's flexibility and storage capacity make it the most efficient and cost-effective way to support the deployment of intermittent renewable resources such as wind power. Wind is variable, partly unpredictable and is impossible to store. Alone, it cannot ensure electrical service at the exact time consumer needs are felt. Integration of wind energy involves the use of supply sides resources to serve load not served by wind generation and to maintain bulk power supply security. Wind power is then combined with other electricity generating resources. They must be brought on line according to wind availability and must be flexible so that output can be quickly adjusted to wind generation.

[81] Programs characteristics (in English) can be found at this website address: http://www.hydroquebec.com/energywise/index.html

Hydroelectric generating stations have an edge over thermal technology because of their very short start up/shutdown times, and their capability of performing load following and load-frequency control on the grid.

## Table Québec-1: Renewable Resources Integration Scenario

**Renewable Resources Integration Scenario - 15% of Québec Internal Demand (in MW).**

| Supply | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| Wind I - 990 MW | 128 | 150 | 560 | 671 | 671 | 671 | 671 | 671 | 671 | 671 |
| Wind II - 2 000 MW | 0 | 0 | 475 | 1,059 | 1,331 | 1,781 | 2,055 | 2,055 | 2,055 | 2,055 |
| Wind III - 500 MW | 0 | 0 | 0 | 100 | 300 | 500 | 500 | 500 | 500 | 500 |
| Wind - HQP - 280 MW | 212 | 437 | 437 | 437 | 437 | 437 | 437 | 437 | 437 | 437 |
| **Total Wind Power** | **340** | **587** | **1,471** | **2,266** | **2,738** | **3,388** | **3,662** | **3,662** | **3,662** | **3,662** |
| | | | | | | | | | | |
| **Biomass (125 MW)** | **0** | **0** | **0** | **0** | **125** | **125** | **125** | **125** | **125** | **125** |
| | | | | | | | | | | |
| Small Hydro - 150 MW | 0 | 0 | 0 | 25 | 50 | 100 | 150 | 150 | 150 | 150 |
| EM-1 A - Hydro | | | 0 | 533 | 768 | 768 | 768 | 768 | 768 | 768 |
| La Sarcelle - Hydro | | | 0 | 100 | 150 | 150 | 150 | 150 | 150 | 150 |
| Rupert Diversion - Hydro | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Complexe de la Romaine - Hydro | | | | 0 | 0 | 622 | 622 | 882 | 1,260 | 1,260 |
| Private Production - 70 MW - Hydro | 0 | 35 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| **Total Hydro** | **0** | **35** | **70** | **728** | **1,038** | **1,710** | **1,760** | **2,020** | **2,398** | **2,398** |
| | | | | | | | | | | |
| **Energy Efficiency - New Programs** | **170** | **340** | **500** | **700** | **880** | **1010** | **1150** | **1150** | **1150** | **1,150** |
| | | | | | | | | | | |
| **Total Supply** | **510** | **962** | **2,041** | **3,694** | **4,781** | **6,233** | **6,697** | **6,957** | **7,335** | **7,335** |

Hydro-Québec considers hydroelectricity to be a highly flexible, clean and renewable basic form of energy.  Wind power is not a substitute for hydroelectricity, but is viewed as a complement.

Hydro-Québec cooperates with Environment Canada in conducting studies to characterize and forecast wind power generation in order to maximize output from this energy source without adversely affecting transmission grid reliability. Hydro-Québec is continuously developing management tools for balancing hydro and wind power, as well as wind turbine and wind farms behaviour simulation models.

Based on the last Hydro-Québec Distribution Procurement Plan (filed with the Québec Energy Board in November 2008) and the Hydro-Québec Production investment plan along with different Québec government decrees, it is shown that the Québec Balancing Authority Area creates a scenario with more than 19 percent of renewable resources.

In 2008, Québec’s internal energy consumption was 188,918 GWh.  This internal demand does not include 5,123 GWh of load reduction due to Energy Efficiency programs.  Therefore, Québec’s internal consumption was 194,041 GWh in 2008 (see Table 1).

# Table Québec-2: Renewable Resources Integration Scenario

**Renewable Resources Integration Scenario - 15% of Québec Internal Demand (in GWh).**

| Load | 2008-Actual | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Québec Internal Demand [1,2] | 188,918 | 186,617 | 187,479 | 190,627 | 193,720 | 195,366 | 197,206 | 199,200 | 203,873 | 207,520 | 209,155 |
| Energy Efficiency | | | | | | | | | | | |
| - 1990's Programs | 2,200 | 2,100 | 2,100 | 2,000 | 2,000 | 1,900 | 1,900 | 1,900 | 1,800 | 1,800 | 1,800 |
| - New Programs | 2,923 | 3,928 | 4,815 | 5,821 | 6,902 | 8,135 | 9,632 | 11,323 | 11,822 | 11,822 | 11822 |
| **Québec Internal Demand** | **194,041** | **192,645** | **194,394** | **198,448** | **202,622** | **205,401** | **208,738** | **212,423** | **217,495** | **221,142** | **222,777** |
| 15 % of Québec Internal Demand: 29,106 | | | | | | | | | | | |

[1] : March 2009 Revision Forecast;
[2] : Québec Internal Load Forecast doesn't includes Energy Efficiency programs.

| Supply | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Wind I - 990 MW | 391 | 460 | 1,715 | 2,056 | 2,056 | 2,056 | 2,056 | 2,056 | 2,056 | 2,056 |
| Wind II - 2 000 MW | 0 | 0 | 100 | 1,600 | 3,300 | 4,600 | 5,400 | 6,300 | 6,300 | 6,300 |
| Wind III - 500 MW | 0 | 0 | 0 | 0 | 400 | 1,000 | 1,600 | 1,600 | 1,600 | 1,600 |
| Wind - HQP - 280 MW | 650 | 1,340 | 1,340 | 1,340 | 1,340 | 1,340 | 1,340 | 1,340 | 1,340 | 1,340 |
| **Total Wind Power** | **1,041** | **1,800** | **3,155** | **4,996** | **7,096** | **8,996** | **10,396** | **11,296** | **11,296** | **11,296** |
| **Biomass (125 MW)** | **0** | **0** | **0** | **100** | **900** | **900** | **900** | **900** | **900** | **900** |
| Small Hydro - 150 MW | 0 | 0 | 0 | 200 | 300 | 600 | 800 | 800 | 800 | 800 |
| EM-1 A - Hydro | | | 950 | 2,320 | 2,320 | 2,320 | 2,320 | 2,320 | 2,320 | 2,320 |
| La Sarcelle - Hydro | | | 60 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Rupert River Diversion - Hydro | | 6,000 | 6,000 | 5,332 | 5,332 | 5,332 | 5,332 | 5,332 | 5,332 | 5,332 |
| Complexe de la Romaine - Hydro | | | | 0 | 0 | 690 | 2,970 | 2,970 | 3,580 | 6,040 |
| Private Production - 70 MW - Hydro | 20 | 254 | 536 | 536 | 536 | 536 | 536 | 536 | 536 | 536 |
| **Total Hydro** | **20** | **6,254** | **7,546** | **9,388** | **9,488** | **10,478** | **12,958** | **12,958** | **13,568** | **16,028** |
| **Marginal Energy Efficiency Programs** | **1,005** | **1,892** | **2,898** | **3,979** | **5,212** | **6,709** | **8,400** | **8,899** | **8,899** | **8,899** |
| **Total Supply** | **2,066** | **9,946** | **13,599** | **18,463** | **22,696** | **27,083** | **32,654** | **34,053** | **34,663** | **37,123** |

Total Supply as percent of Québec Internal Demand: 19.1%

Energy Efficiency as percent of Québec Internal Demand: 4.6%

## Table Québec-3: Renewable Resources Integration Scenario

**PLANNED RESOURCES in MW** (1)

| Call for Tenders - Wind I | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| - St-Ulric - St-Léandre | 127.5 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| - Les Méchins | | | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| - Mont-Louis | | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 |
| - Montagne-Sèche | | | 58.5 | 58.5 | 58.5 | 58.5 | 58.5 | 58.5 | 58.5 | 58.5 |
| - Gros-Morne 1 | | | 110.5 | 110.5 | 110.5 | 110.5 | 110.5 | 110.5 | 110.5 | 110.5 |
| - Gros-Morne 2 | | | | 111 | 111 | 111 | 111 | 111 | 111 | 111 |

| Call for Tenders - Wind II | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| - Des Moulins | | | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 |
| - St-Rémi | | | | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| - St-Valentin | | | | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| - De l'Érable | | | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| - Massif du Sud | | | | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| - Seigneurie de Beaupré 2 | | | | | 132.6 | 132.6 | 132.6 | 132.6 | 132.6 | 132.6 |
| - Seigneurie de Beaupré 3 | | | | | 139.6 | 139.6 | 139.6 | 139.6 | 139.6 | 139.6 |
| - Clermont | | | | | | | 74 | 74 | 74 | 74 |
| - Rivière du Moulin Ph 1 | | | | | | 150 | 150 | 150 | 150 | 150 |
| - Rivière du Moulin Ph 2 | | | | | | | 200 | 200 | 200 | 200 |
| - Ste-Luce | | | | 68 | 68 | 68 | 68 | 68 | 68 | 68 |
| - Lac Alfred Ph 1 | | | | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| - Lac Alfred Ph 2 | | | | | 150 | 150 | 150 | 150 | 150 | 150 |
| - New Richmond | | | | 66 | 66 | 66 | 66 | 66 | 66 | 66 |
| - Le Plateau | | | 138.6 | 138.6 | 138.6 | 138.6 | 138.6 | 138.6 | 138.6 | 138.6 |
| - Aguanish | | | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| - MRC la Matépédia | | | | | | 100 | 100 | 100 | 100 | 100 |

| Call for Tenders - Wind III | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| - 2 X 250 MW | | | | 100 | 300 | 500 | 500 | 500 | 500 | 500 |

| Call for Tenders - Biomass II | | | | 125 | 125 | 125 | 125 | 125 | 125 | 125 |
|---|---|---|---|---|---|---|---|---|---|---|

| Call for Tenders - Small Hydro | | | 25 | 50 | 100 | 150 | 150 | 150 | 150 | 150 |
|---|---|---|---|---|---|---|---|---|---|---|

| Hydro-Québec Production | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| - Eastmain-1 A | | | 533 | 768 | 768 | 768 | 768 | 768 | 768 | 768 |
| - La Sarcelle | | | 100 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| - La Romaine Complex | | | | | | 622 | 622 | 882 | 1260 | 1260 |

| Private Producers - Small Hydro | 35 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
|---|---|---|---|---|---|---|---|---|---|---|

(1) : For Wind Power, the In-Service dates are December 1st of the indicated year and for hydro and Biomass Power, the In-Service dates are November 1st of the undicated year.

## Eastmain-1 A/Sarcelle/Rupert Project

The project consists in building a 768 MW generating station – Eastmain-1 A powerhouse – near the existing Eastmain-1 powerhouse, and diverting part of the flow of the Rupert River into these two facilities, then through Sarcelle powerhouse and on to Robert-Bourassa (LG-2), La Grande-2-A and La Grande-1 generating stations.

The Rupert diversion will involve the following structures and facilities:

- four dams.
- a spillway on the Rupert River, which will also function as an instream flow release structure.
- 74 dikes.
- two diversion bays (forebay and tailbay) with a total area of about 346 km$^2$ at maximum operating level.
- a 2.9 km long tunnel between the Rupert forebay and tailbay.
- a network of canals with a total length of about 12 km to facilitate flow in the various portions of the diversion bays.
- Hydraulic structures on the Rupert River to maintain post-diversion water levels along approximately 48 percent of the river's entire length.

The project, scheduled for commissioning in 2011 through 2012, will give Hydro-Québec's generating fleet an additional capacity of 918 MW and an additional output of 8.5 TWh per year, distributed as follows:[82]

1. additional output at Eastmain-1-A and Eastmain-1 powerhouses: 2.3 TWh.
2. output at La Sarcelle powerhouse: 0.9 TWh.
3. additional output at Robert-Bourassa, La Grande-2-A and La Grande-1 generating stations: 5.3 TWh.

Romaine Complex

Hydro-Québec Production has obtained the necessary approvals to build a 1,550 MW hydroelectric complex on the Rivière Romaine, on the lower north shore of the St-Lawrence River. The complex will consist of four hydro generating stations with an annual output of 8.0 TWh. Construction has begun in March of 2009 and is scheduled to be completed in 2020. The first Romaine commissioning is planned for 2014. Project information, in English, is available at this web address: http://www.hydroquebec.com/romaine/pdf/2009G133_la_romaine_en.pdf

### Capacity Transactions on Peak

Québec has a 200 MW firm purchase contract with New Brunswick until October 2011.

There are two firm export contracts. One is with Ontario (145 MW) until the end of the horizon of this study. The other contract is with New England (310 MW until the end of 2011).

Hydro-Québec Distribution includes, when planning its resources, a potential of 1,000 MW of interconnection assistance for winter months (mainly from the state of New York). When needed, short term calls for tenders are launched and transmission capacity is reserved for those short term purchases. Hydro-Québec Production can participate in theses calls for tenders.

### Transmission

In 2009 TransÉnergie has commissioned a new 2 X 625 MW back-to-back HVdc interconnection with IESO in the Ottawa-Gatineau Area across the Ottawa River (The Outaouais Interconnection). This station is integrated into the 315 kV double-circuit existing line from Chénier in the Montréal Area to Vignan in the Gatineau Area. The Ontario side of the station is a 240 kV section integrating a double-circuit 240 kV line from Hawthorne substation in Ottawa.

In 2010, a new 315 kV double-circuit line between Chénier and Outaouais and a fourth 735/315-kV transformer will be added to permit full use of the interconnection.

[82] Information regarding this project can be found at these websites:
http://www.hydroquebec.com/rupert/en/index.html
http://www.hydroquebec.com/eastmain1/en/batir/resume.html

The following table shows the transmission line additions through this report's horizon.[83]

**Table Québec-4: Projected Transmission Additions**

| Transmission Project Name From / To | Voltage (KV) | Length (Miles) | In-Service Date(s) |
|---|---|---|---|
| Les Méchins / Line 23 YY | 230 | 6.3 | Dec-2009 |
| Goemon / Mont-Louis | 315 | 46.3 | Dec-2010 |
| Goemon / Gros Morne | 315 | 55.6 | Dec-2011 |
| Chénier / Outaouais | 315 | 70.6 | May-2010 |
| Eastmain-1A / Eastmain-1 | 315 | 1.2 | July-2010 |
| Sarcelle / Eastmain-1 | 315 | 68.8 | July-2010 |
| Romaine-2 / Arnaud | 315 | 162.9 | Dec-2014 |
| Romaine-1 / Romaine-2 | 315 | 19.1 | Dec-2016 |
| St-Ulric-Saint-Léandre line | 230 | 3.7 | Dec-2009 |
| Rimouski-Les Boules line | 230 | 39.1 | July-2009 |
| Les Méchins wind farm line | 230 | 2.5 | Dec- 2011 |
| Montagne Sèche wind farm line | 161 | 22.4 | Dec- 2011 |
| Des Moulins wind farm line | 230 | 1.9 | Dec-2011 |
| Lac Alfred wind farm line | 315 | 17.4 | Dec-2013 |
| De L'Érable wind farm line | 120 | 9.3 | Dec-2011 |
| Massif du Sud wind farm line | 150 | 12.4 | Dec-2012 |

In addition to the equipment required to connect the wind plants to the transmission network, a number of transmission reinforcements are necessary in order to respect thermal limits. Moreover, to enable reliable and secure integration of wind farms to the transmission system system design criteria and technical requirements must be met. Wind plants should achieve a performance comparable to conventional power plants (equipped with synchronous generators):

- Under and over-voltage ride-through capability;
- Voltage reduction capability (reactive power);
- Frequency regulation capability (active power);
- Under and over-frequency ride-through capability.

The geography of the Québec Balancing Authority Area is such that the system consists of two major branches – one emanating from the La Grande Generation Complex (Western branch) and the other emanating from Churchill-Falls and the Manicouagan-Outardes Generation Complex (Eastern branch). These branches join in the southern part of the system where the major load

[83] Information regarding these transmission projects can be founded at these addresses:
http://www.hydroquebec.com/projects/integration_parcs_eoliens_1.html
http://www.hydroquebec.com/projects/integration_parcs_eoliens_2.html
http://www.hydroquebec.com/projects/sarcelle_eastmain_1.html
http://www.hydroquebec.com/projects/romaine_transport.html
http://www.hydroquebec.com/projects/pdf/montagne-decision.pdf
http://www.hydroquebec.com/projects/pdf/lac_alfred.pdf
http://www.hydroquebec.com/projects/pdf/goemon-decision-avril-2009.pdf
http://www.hydroquebec.com/projects/pdf/rimouski_200804.pdf

centers are situated. The distance between these large generation complexes and the load centers are in the order of 700 to 800 miles.

TransÉnergie, the Transmission Operator, operates an extensive transmission system in order to provide the necessary access to resources and to loads. The following table shows the main load-end substations and associated transmission to be built during the study horizon.

| Table Québec-5: Projected Transmission Additions | | | |
|---|---|---|---|
| **Transmission Project Name From / To** | **Voltage (KV)** | **Length (Miles)** | **In-Service Date(s)** |
| ***In Progress - New Installations*** | | | |
| **Mont-Tremblant station** | 120-25 kV | | Dec-2009 |
| **and Line** | 120 | 4,8 | Dec-2009 |
| **Vaudreuil-Soulanges station** | 120-25 kV | | Nov-2009 |
| ***In Progress - Restorations*** | | | |
| **Delson station** | 120 | | Nov-2009 |
| **Saint-Basile station** | 120 | | Nov-2010 |
| **Sorel Station** | 120 | | Nov-2010 |
| ***Planned - New Installations*** | | | |
| **Anne- Hébert station** | 315-25 kV | | Fall 2010 |
| **and Line** | 315 | 8,2 | Fall 2010 |
| **Beauceville - Sainte-Marie** | 120 | 18,6 | Spring 2011 |
| **Montcalm station** | 230-25 kV | | 2012 |
| **Neubois station** | 120-25 kV | | Fall 2012 |

No delay with any of these projects is expected. A delay in any particular project would not affect Bulk System reliability.

## Operational Issues

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

One major anticipated unit outage (Gentilly-2 nuclear unit of 675 MW) is scheduled from late 2010 to mid-2012 but this outage will not impact reliability. Variable resources, transmission additions and temporary operating measures are not expected to negatively impact reliability during the next ten years.

Non-hydraulic resources account only for a small portion of total resources. Plants using oil or jet fuel are refuelled by boat or by truck and generally not during the winter season. Natural gas is used at a single cogeneration plant and is delivered under a firm natural gas purchase contract.

Operational planning studies are being continuously conducted by TransÉnergie, the Québec Area controller. Yearly peak demand period studies are conducted to assess system conditions during winter peak periods. Extreme weather in Québec translates into very low temperatures during the Winter Operating Period. Through a transmission planning criterion, transmission planning studies must take into account a 4,000 MW load increase above the normal load forecast on the system during such extreme weather conditions. This is equivalent to 110 percent of system peak load. Québec relies on both internal and external resources to serve this additional load and transmission capacity is available.

### Reliability Assessment Analysis

To determine whether existing and planned resources provide an adequate level of reliability, Québec uses the NPCC resource adequacy criterion, a loss of load expectation (LOLE) of 0.1 day/year. The last Québec Area Comprehensive Review of Resource Adequacy, approved by the NPCC Reliability Coordination Committee (RCC) in March 2009, indicates that a long term required reserve of 11.7 percent of the peak load is needed.[84] This percentage can vary if the future resources have different characteristics or the load uncertainty varies. The Québec Area treats short term (i.e., 1 through 4 years) and long term (5 years and more) Reserve Margins requirements slightly differently. The long term required reserve is equal to the fourth year of the assessment. This four-year time frame gives sufficient time to build new peaking units or to find new demand side resources.

As shown in the next table, until 2015/2016, the Québec Area has surplus resources. For the last three years of this assessment, additional resources are needed to respect the NPCC reliability criterion (750 MW in 2016/2017, 850 MW in 2017/2018 and 1,200 MW in 2018/2019). At that time, Québec will have close to 4,000 MW of wind power as installed capacity. In this assessment of reliability wind power is derated to zero. If a capacity factor of 30 percent was used to assess reliability, wind power represents an equivalent peak capacity of 1,200 MW and reserve margins would be within target.

**Table Québec-6: Demand, Resources, and Reserves**

**Demand, Resources and Reserves (in MW)**

| YEAR | Net Internal Demand (A) | Deliverable Capacity Resources (B) | Planned Reserves (C = B-A) | Planned Reserves % (D = C/A) |
|---|---|---|---|---|
| 2009/2010 | 34,500 | 40,182 | 5,682 | 16.5% |
| 2010/2011 | 35,353 | 40,190 | 4,837 | 13.7% |
| 2011/2012 | 35,826 | 40,013 | 4,187 | 11.7% |
| 2012/2013 | 36,313 | 41,402 | 5,089 | 14.0% |
| 2013/2014 | 36,672 | 41,452 | 4,780 | 13.0% |
| 2014/2015 | 37,391 | 42,124 | 4,733 | 12.7% |
| 2015/2016 | 37,675 | 42,108 | 4,433 | 11.8% |
| 2016/2017 | 38,570 | 42,331 | 3,761 | 9.8% |
| 2017/2018 | 39,000 | 42,709 | 3,709 | 9.5% |
| 2018/2019 | 39,306 | 42,709 | 3,403 | 8.7% |

Hydro-Québec's energy requirements are mostly met by hydro generating stations, which are located on different river systems scattered over a large territory. The major plants are backed by multi-year reservoirs (water reserves lasting more than one year). The Québec Balancing

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

Authority Area can rely on those multi-year reservoirs and on some other non-hydraulic sources, including fossil generation, allowing it to cope with inflow variations.

Hydro-Québec Production's hydro generating units can be classified into three categories: run-of-river units, annual reservoir and multi-annual reservoir hydro generating units. Each category copes with low water inflows in a different way:

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

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

To assess its energy reliability, Hydro-Québec developed an energy criterion that states that sufficient resources should be available to run through sequences of two or four years of low inflows having a 2 percent probability of occurrence. Hydro-Québec must demonstrate its ability to meet this criterion three times a year to the Québec Energy Board.[85]

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

- reduction of the energy stock in reservoirs to a minimum of 10 TWh at the beginning of May.
- external non-firm energy sales reductions.
- production of thermal generating units during an extended period of time.
- purchases from neighboring areas.

### Other Region-Specific Issues that were not mentioned above

Hydro-Québec considers hydropower (small and large) as a renewable resource. The U.S. Department of Energy (DOE) in a number of publications has made several references to hydropower as a renewable resource:

"Water is currently the leading renewable energy source used by electric utilities to generate electric power. The major advantage is that water is a source of cheap power. In addition, because there is no fuel combustion, there is little air pollution in comparison with fossil fuel plants and limited thermal pollution compared with nuclear plants."[86]

---

85 The last assessment can be found on the Québec Energy Board website: http://www.regie-energie.qc.ca/audiences/Suivis/Suivi-D-2008-133_Criteres/HQD_R-3648-2007_Annexes_Suivi_D2008-133_3juin09.pdf.

86 http://www.eia.doe.gov/cneaf/solar.renewables/page/hydroelec/hydroelec.html

"Hydropower relies on the water cycle, which is driven by the sun, thus it's a renewable power source."[87]

"The DOE program conducts research to improve two renewable energy technologies: hydropower and wind energy."[88]

"Competitive Electric Power from Renewable Energy

- About 10 percent of United States electricity comes from hydropower;
- More than 75 percent of the nation's renewable energy is generated by hydropower."[89]

"Hydropower is using water to power machinery or make electricity. Water constantly moves through a vast global cycle, evaporating from lakes and oceans, forming clouds, precipitating as rain or snow, and then flowing back down to the ocean. The energy of this water cycle, which is driven by the sun, can be tapped to produce electricity. Hydropower uses a fuel – water – that is not reduced or used up in the process. Because the water cycle is an endless, constantly recharging system, hydropower is considered a renewable energy."[90]

"The 2002 United Nations World Summit on Sustainable Development identified all hydro as a renewable source of energy to be supported by the international community."[91]

### Region Description

*The Québec area is winter peaking. The all-time internal peak demand was 37,230 MW set on January 16, 2009. The summer peak demands are in the order of 21,000 MW. The installed capacity in January 2009 was 41,689 MW, of which 38,953 MW (93.4 percent) was hydroelectric capacity. There are more than 140 generating stations on the Québec electrical system.*

*The transmission voltages on the Québec's system are 735, 315, 230, 161 and 120 kV. Transmission line length totals about 33,060 km (20,540 miles).*

*Québec electrical system is a separate Interconnection from the Eastern Interconnection into which other NPCC Areas are interconnected. TransÉnergie, the Transmission Owner and Operator in Québec, has interconnections with Ontario, New York, New England and the Maritimes. Interconnections consist of either HVdc ties or radial generation or load to and from neighbouring systems.*

*The population served is around 7 million and the Québec area covers about 1,668,000 km$^2$ (643,848 square miles). Most of the population is grouped along the St-Lawrence River axis and the largest load area is in the Southwest part of the province, mainly around the Greater Montréal area.*

87 http://www1.eere.energy.gov/windandhydro/hydro_ad.html
88 http://www1.eere.energy.gov/windandhydro/program_Areas.html
89 http://www1.eere.energy.gov/windandhydro/about.html
90 http://www1.eere.energy.gov/windandhydro/hydro_how.html
91 http://www.hydropower.org/downloads/F4%percent20Hydropower%percent20Making%percent20a%percent20Significant%percent20Contribution%percent20Worldwide.pdf

# RFC

## Introduction

All RFC members are affiliated with either the Midwest ISO (MISO) or the PJM Interconnection (PJM) Regional transmission organization (RTO) for operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission company located in Indiana, Kentucky and Ohio, is not a member of either RTO and is not affiliated with their markets; however, OVEC's Reliability Coordinator services are performed by PJM. Also, MISO began operation of its Ancillary Services Market (ASM) on January 6, 2009, which included operation as a single Balancing Authority.[92]

RFC does not have officially-designated subregions. About one-third of the RFC load is within MISO and nearly all remaining load is within PJM, except for about 100 MW of load within the OVEC Balancing Authority area. From the RTO perspective, approximately 60 percent of the MISO load and 85 percent of the PJM load is within RFC. The PJM RTO also spans into the SERC Region, and the MISO RTO also spans into the MRO and SERC Regions. The MISO and PJM RTOs each operate as a single Balancing Authority.

For this special scenario analysis assessment, RFC has relied solely upon the recently completed 2008 Joint Coordinated Study Plan (JCSP) for data and results, since the JCSP study area included both MISO and PJM (i.e. all of the RFC footprint) and most of the Eastern Interconnection within the United States The JCSP effort was an initial collaboration of ISOs and RTOs (including MISO and PJM) within the Eastern Interconnection on a conceptual study to examine the effects of integrating large amounts of wind generation into the bulk electric transmission system between 2008 and 2024. This assessment report represents only the data and results for the RFC footprint. The JCSP effort produced two analyses and two reports. The first analysis was an economic study using 2008 and 2024 as the study years. The JCSP economic study developed and analyzed the costs and benefits of conceptual transmission overlays for the two scenarios. The second study was a reliability analysis focusing on the study year 2018 and its objective was to assess the steady-state performance of the projected transmission system in 2018. The study scope was limited to monitoring transmission facilities operated 200 kV and above for steady-state thermal and voltage criteria violations under base case and contingency conditions. This assessment uses only the JCSP economic study results.

The JCSP economic effort studied two cases, a Reference *Scenario Case* and a 20 percent Wind Energy *Scenario Case*. This RFC Scenario Assessment uses slightly modified JCSP Reference Scenario data for 2018 as the RFC *Reference Case*. The generation data includes the expected future generation in RFC that was included in the NERC 2008 *Long-Term Reliability Assessment* through 2017 with additional generation in 2018 to match the requirements in the JCSP analysis for planned generation. The demand and energy data is identical to RFC's 2008 NERC *Long-Term Reliability Assessment* through 2017, with the 2018 demand and energy data equal to the JCSP demand and energy data for 2018. The JCSP Reference Scenario also includes

[92] More information is available at: http://www.midwestmarket.org/publish/Folder/469a41_10a26fa6c1e_-741b0a48324a.

transmission system facility additions needed to accommodate this expected new generation, including the wind generation. On average for the JCSP Reference Scenario, about 5 percent of the energy use in the Eastern Interconnection was assumed to be generated from wind. The wind generation sited within the RFC footprint amounts to about 4 percent of the energy needs in 2018 in this *Reference Case*.

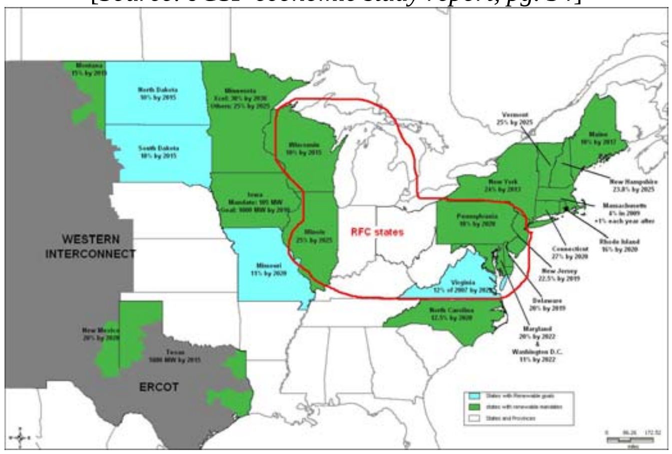
The RFC Scenario Assessment also uses the 20 percent Wind Energy Scenario as described in the JCSP study for its *Scenario Case*. This case assumes that the entire Eastern Interconnection study area would meet 20 percent of its energy needs using wind generation by the year 2024. This scenario also identified a conceptual transmission overlay to accommodate this future scenario. In this scenario, large amounts of wind generation were sited in the western part of the Eastern Interconnection (specifically in the MRO and SPP footprints) where there are superior inland wind resources. This wind siting assumption creates a west-to-east power flow bias through the Eastern Interconnection. The wind generation sited within the RFC footprint adds up to about 12 percent of the RFC energy needs in 2018 for this scenario. When the amount of wind generation that is expected to be imported into the RFC Region is included, approximately 14 percent of the forecast energy needs in 2018 would be met by wind resources. However, the energy from many wind resource sites in western areas of RFC (in MISO) would be imported to the eastern areas of RFC (to PJM), which is consistent with the west-to-east power flow bias in this scenario.

The *Reference Case* includes 15,000 MW of nameplate wind generation by 2018. The Wind *Scenario Case* associated with this *Reference Case* includes 40,600 MW of nameplate wind generation in 2018 (25,600 MW of additional nameplate wind generation compared to the *Reference Case*).

In the study, large amounts of wind generation are conceptually being sited in the western part of the Eastern Interconnection (specifically in the MRO and SPP footprints) where there are superior inland wind resources to more economically serve load on the east coast of the United States This wind siting assumption creates a west-to-east power flow bias through the Eastern Interconnection and through RFC. Also, many new transmission lines that would be routed through RFC would need to accommodate this large transfer of power.

The JCSP Reference Scenario calculated the amount and sites for wind generation based upon meeting existing Renewable Portfolio Standards (RPS) incremental requirements as of January 1, 2008. Figure 1 below shows those RPS assumptions. After January 2008 (which was not included in the study), the state of Michigan now has an RPS mandate of 10 percent by 2015, Ohio has an RPS mandate of 25 percent by the year 2025, and West Virginia has introduced a bill for an RPS of 10 percent by the year 2015, escalating to 20 percent by 2020, and then 25 percent by the year 2025.

**Figure RFC-1: RPS Mandates and Goals by State, as of January 1, 2008**
[*Source: JCSP economic study report, pg. 34*]



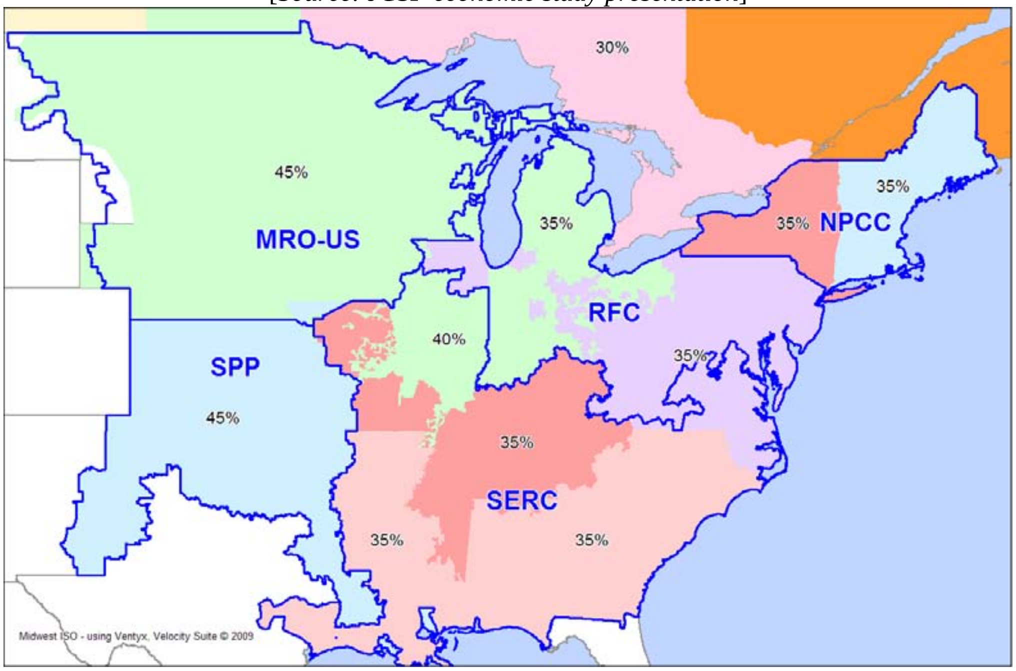

In the JCSP study, all wind generation in the Reference Scenario is carried forward to the 20 percent Wind Energy Scenario, and in this Scenario, assumes that a federal 20 percent wind-only energy mandate is met by 2024.

All states with RPS provisions which require a phasing-in of capacity with specific milestone requirements are included in the JSCP wind calculations. In the JSCP study, 2010 was the first year that wind generators were placed in-service due to the two year construction lead time.

The JCSP study assumed the same percentage level of demand response for the 2024 case as existed in 2008 (i.e. if there was a 2.5 percent demand response level in 2008, then new demand response additions were made out through 2024 to maintain that 2.5 percent share). In the RFC *Reference* and *Scenario Cases*, the amount of demand response (6,900 MW) was kept constant for each study year. Energy efficiency was embedded within the demand forecast.

Figure 2 below shows the Regional capacity factors of future wind generators for energy use used in the JCSP economic study. Within RFC, the study used a 35 percent capacity factor for the PJM area, 40 percent for the MISO Indiana/Ohio area, 35 percent for Michigan, and 45 percent for the Wisconsin area.

**Figure RFC-2: JCSP Regional Capacity Factors Used for Future Wind Generators**
[*Source: JCSP economic study presentation*]




The JCSP study made several assumptions for the siting of future generation[93]. Those assumptions include not using transmission location as an initial factor, siting proxy generation by Region, avoiding Greenfield sites for natural gas fired units, limiting plant size to 2,400 MW maximum capacity, and siting base load steam capacity in 600 MW increments and nuclear capacity in 1,200 MW increments.

For the conceptual transmission overlays, four JCSP workshops were held to obtain input from the respective transmission owners. Input for future transmission facilities were solicited from each workshop and were integrated into the initial conceptual overlay with some adjustments made later. Further post-workshop refinements, such as changing the new line termination points, were made to improve benefits and reduce costs.

Key issues and results of this scenario assessment are discussed below.

## Demand

In using the JCSP study for this scenario assessment effort, RFC had to reconcile differences between the JCSP study data and the RFC 2008-2017 *Long-Term Reliability Assessment* data. RFC added the year 2018 to the 2008 *Long-Term Reliability Assessment* data forms, and used the JCSP Net Energy for Load. While the JCSP study assumes a decreasing load factor over the study period, RFC kept a relatively constant load factor between 2017 -2018, resulting in a peak demand forecast for 2018 that is significantly below the JCSP study demand for 2018. Since the wind scenario is primarily an energy analysis, the differences in demand do not impact the reliability results of the scenario analysis. For this assessment, RFC has a 210,000 MW Total

[93] See JCSP economic study report, Section 5.2 - Siting Proxy Generation, pg. 50

Internal Demand (TID) in 2018. The Net Internal Demand (NID) is 203,100 MW. These demand values are the same for the reference and *Scenario Cases*.

### Generation

Figure 3 shows the location of the projected future generation locations in the *Reference Case* (i.e. reference future). Figure 4 shows the location of the projected future generation for the *Scenario Case* (i.e. 20 percent Wind Energy Scenario).

The amount of generating capacity included in the JCSP study is used in this assessment as the capability of the generation in RFC. JCSP utilized a 15 percent reserve margin to determine the appropriate amount of generation to satisfy this reserve requirement. The difference in capacity between the *Reference Case* and the *Scenario Case* is due to changes in wind generation, coal generation and combustion turbine generation.

The “Certain” resources and the “Planned” capacity additions are the same in both reference and *Scenario Cases*. All the changes are due to changes in the category of “Proposed” generation.

In this assessment, the amount of available wind power capability included in the reserve calculations is less than the nameplate rating of the wind resources. The difference between the nameplate rating and the expected wind capability is accounted for in the “Existing, Other” category.

Scheduled maintenance and inoperable capacity are not included in this assessment when calculating the reserve margins.

RFC GENERATION

The RFC data only includes generation physically located within the RFC Region. Generating capacity outside the Regional area owned by member companies is included with the scheduled power imports. Since the *Scenario Case* is a wind energy scenario, there are no differences expected in biomass generation between the cases. Impacts of potential carbon capture/sequestration are not included in this assessment.

The amount of “Certain” capacity in both the RFC *Reference Case* and *Scenario Case* is 213,700 MW. The amount of “Planned” capacity is also the same in both the reference and *Scenario Cases*, at 5,800 MW. This results in 219,500 MW of on-peak capacity and 222,100 MW of nameplate capacity in 2018.

The capacity difference between the reference and *Scenario Cases* is in the “Proposed” capacity category. Due to the uncertainty of Proposed capacity additions, confidence factors were provided by PJM and MISO based upon their analyses of the likelihood of project completion and current generator queue status. These confidence factors were used to approximate the amount of capacity that needed to be proposed such that the expected installed capacity in 2018 would be equivalent to the capacity in the JCSP reference and *Scenario Cases*. The nameplate amount of capacity for RFC in the *Reference Case* is 262,900 MW. This assumes that 40,800 MW of nameplate capacity would be installed from projects identified in the MISO and PJM generator interconnection queues and other projects yet to be identified or announced. These assumed capacity additions consist of 12,000 MW of wind generation and 28,800 MW of fossil, nuclear and hydro generation.

The nameplate amount of capacity for RFC in the wind *Scenario Case* is 283,000 MW. The 60,900 MW capacity assumed to be installed from projects identified in the MISO and PJM generator interconnection queues and other projects yet to be identified or announced, consists of 37,600 MW of wind generation and 23,300 MW of fossil, nuclear and hydro generation. Therefore, the *Scenario Case* contains 25,600 MW of additional wind generation along with a 5,500 MW net reduction in other generation.

Assuming that 20 percent of the nameplate rating of wind resources would be available at the time of the summer peak, the amount of on-peak capacity committed to serve net internal demand in the RFC area is 250,700 MW in the *Reference Case* and 250,300 MW in the *Scenario Case*. The reserve margin for both the reference and *Scenario Cases* are 23 percent, which exceeds the 15-16 percent target reserve margins in the Region.

Deliverability of capacity is not specifically addressed in this report. One purpose of the scenario analysis is to determine, in general, the impacts of large amounts of wind power on the system as a result of renewable portfolio standards. The JCSP study developed a transmission overlay to enable the large-scale transfer of power between different Regions of the country. The JCSP study did not evaluate the necessary underlying lower voltage transmission network needed to make those transfers deliverable to the load. For the resource analysis portion of this assessment, it was assumed that there would be no appreciable constraints on the delivery of any resource to load.

The potential impact of adverse weather conditions and fuel supply issues were not developed for this scenario assessment.

**Figure RFC-3: Future Generator Location for the Reference Scenario**
[*Source: JCSP economic study presentation*]

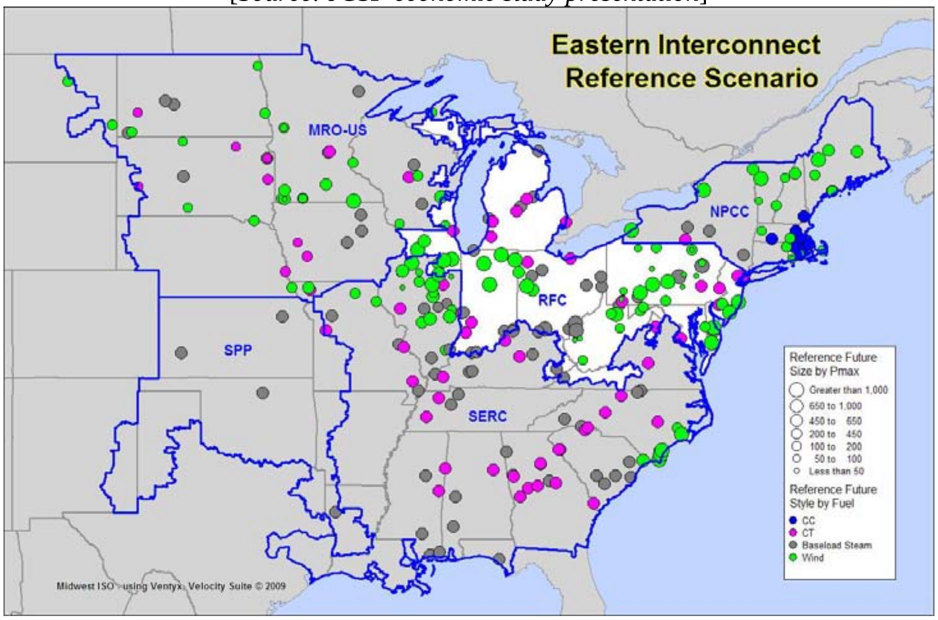
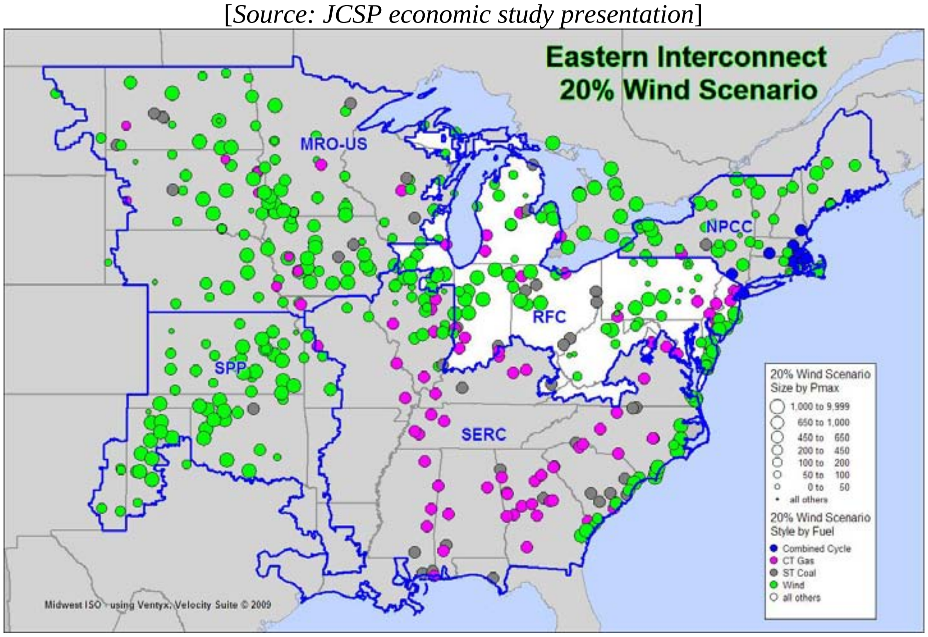



**Figure RFC-4: Future Generator Location for the 20 percent Wind Scenario**
[*Source: JCSP economic study presentation*]




## Capacity Transactions on Peak

The *Reference Case* continued with the same level of committed power transfers as the 2008 *Long-Term Reliability Assessment* assessment. In the 2008 *Long-Term Reliability Assessment*, the capacity imports and exports were balanced, so there was no net import or export. The difference between capacity amounts within the RFC area and the ownership entitlements in the JCSP *Reference Case* and wind *Scenario Cases* in 2018 were included as the import change for the *Scenario Case*. The wind *Scenario Case* assumes a net import on-peak of 2,300 MW.

## Transmission

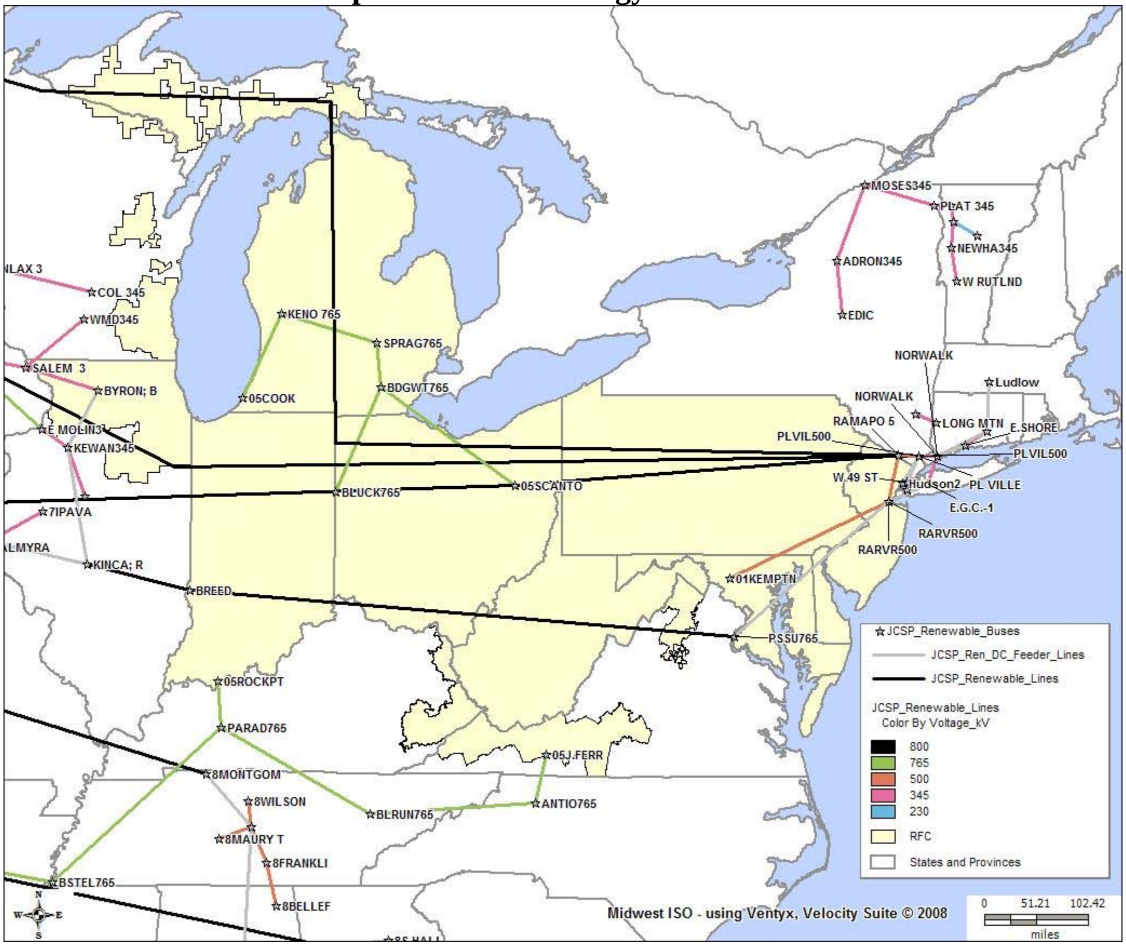
Figure 5 below graphically shows the additional transmission lines added within the RFC footprint for the JCSP Reference *Scenario Case*. Figure 6 graphically shows the additional transmission lines added within the RFC footprint for the JCSP 20 percent Wind Energy *Scenario Case*. Table 1 lists the details of the additional transmission lines and Table 2 lists the transformers for the JCSP Reference and 20 percent Wind Energy Scenarios for the year 2024. Table 1 includes the additional HVdc transmission lines for both *Scenario Cases*. There are no additional SVC or FACTS devices listed for either of the two scenarios.

**Figure RFC-5: JCSP Additional Transmission Lines within the RFC Footprint for the Reference Scenario**

**Table RFC-1: JCSP Additional Transmission Lines for the Reference and 20 percent Wind Energy Scenarios within the RFC Footprint**

| NERC RE(s) | From Bus Name | To Bus Name | Double Circuit | Voltage (kV) | RFC Line Length (Miles) | Reference Scenario | 20 percent Wind Energy Scenario |
|---|---|---|---|---|---|---|---|
| MRO\RFC | SALEM 345 | BYRON 345 | | 345 | 74 | | x |
| SERC\RFC | NEWTON 345 | MEROM 345 | | 345 | 43.2 | x | |
| SERC\RFC | CLINTON 345 | DEQUINE 345 | | 345 | 92.9 | x | |
| RFC | KEMPTON 500 | SAYERVILLE 500 | x | 500 | 176 | x | x |
| RFC\NPCC | SAYERVILLE 500 | RAMAPO 500 | x | 500 | 46.2 | x | |
| RFC\NPCC | SAYERVILLE 500 | RAMAPO 500 | | 500 | 46.2 | | x |
| NPCC\RFC | WATERCURE 765 | ERIE SOUTH 765 | | 765 | 167 | x | |
| RFC | SPRAGUE CRK 765 | BRIDGE WATER 765 | | 765 | 46 | x | x |
| RFC | KENO 765 | SPRAGUE CRK 765 | | 765 | 81 | x | x |
| RFC | GREENTOWN 765 | BLUE CRK 765 | | 765 | 59 | x | |
| RFC | BRIDGE WATER 765 | SOUTH CANTON 765 | | 765 | 163 | x | x |
| RFC | BRIDGE WATER 765 | BLUE CRK 765 | | 765 | 110 | x | x |
| RFC | COOK 765 | KENO 765 | | 765 | 101 | x | x |
| RFC | PERRY 765 | SOUTH CANTON 765 | | 765 | 75 | x | |
| RFC | ERIE SOUTH 765 | PERRY 765 | | 765 | 58 | x | |
| RFC | ROCKPORT 765 | GREENTOWN 765 | | 765 | 187 | x | |
| RFC | NELSON 765 | PLANO 765 | | 765 | 59 | x | |
| RFC\SERC | NELSON 765 | QUAD CITY 765 | | 765 | 36.8 | x | |
| SERC\RFC | ANTIOCH 765 | JACKSON FERRY 765 | | 765 | 51 | x | x |
| SERC\RFC | EW FRANKFORT 765 | ROCKPORT 765 | | 765 | 98.5 | x | |
| SERC\RFC | CLOVER 765 | JOSHUA FALLS 765 | | 765 | 43 | x | |
| SERC\RFC | PARADISE 765 | ROCKPORT 765 | | 765 | 46 | x | x |
| SERC\RFC | CLOVER 765 | AXTON 765 | | 765 | 58.2 | x | |
| SERC\RFC | CUNNINGHAM 765 | JOSHUA FALLS 765 | | 765 | 47.4 | x | |
| SERC\RFC\NPCC | POSSUM POINT | E GARDEN CITY 345 | | 400 HVdc | 470 | x | |
| MRO\RFC\NPCC | ARROWHEAD 500 | NORWALK | | 800 HVdc | 1620 | | x |
| MRO\RFC\NPCC | BROOKINGS 345 | PLEASANTVILLE | | 800 HVdc | 1450 | | x |
| MRO\SERC\RFC | COOPER 765 | SOUTH CANTON | | 800 HVdc | | | |
| RFC\NPCC | SOUTH CANTON | RAMAPO | | 800 HVdc | 1300 | | x |
| SERC\RFC | KINCAID | BREED | | 800 HVdc | | | |
| RFC\SERC | BREED | POSSUM POINT | | 800 HVdc | 1050 | | x |
| SERC\RFC\NPCC | KINCAID | NORWALK | | 800 HVdc | 1300 | x | |
| SERC\RFC\NPCC | BRAIDWOOD 345 | PLEASANTVILLE | | 800 HVdc | 1100 | x | |

**Figure RFC-6: JCSP Additional Transmission Lines within the RFC Footprint for the 20 percent Wind Energy Scenario**




| Table 2: JCSP Additional Transformers for the Reference and 20 percent Wind Energy Scenarios in the RFC Footprint | | | | | |
|---|---|---|---|---|---|
| **NERC RE** | **From Bus Name** | **To Bus Name** | **Voltage (kV)** | **Reference Scenario** | **20 percent Wind Energy Scenario** |
| RFC | SAYERVILLE 500 | SAYERVILLE 230 | 500/230 | x | x |
| RFC | KENO 765 | KENO 345 | 765/345 | x | x |
| RFC | SPRAGUE CRK 765 | SPRAGUE CRK 345 | 765/345 | x | x |
| RFC | BRIDGE WATER 765 | BRIDGE WATER 345 | 765/345 | x | x |
| RFC | PERRY 765 | PERRY 345 | 765/345 | x | |
| RFC | ERIE SOUTH 765 | ERIE SOUTH 345 | 765/345 | x | |
| RFC | NELSON 765 | NELSON 345 | 765/345 | x | |

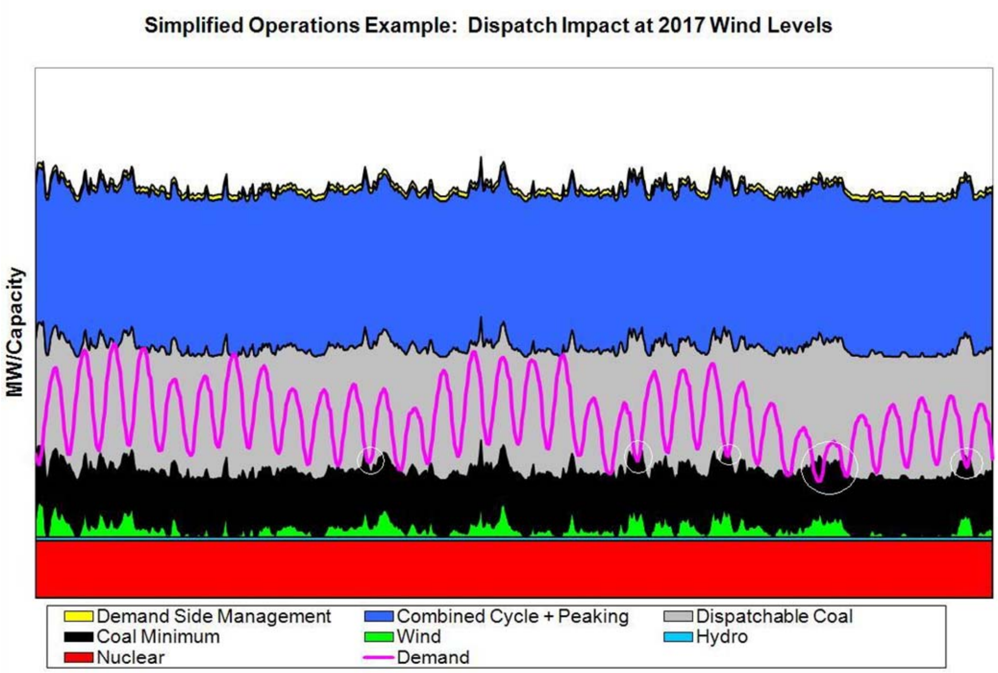
## Operational Issues

The following issues are some operational considerations from this scenario assessment, and may represent some concern depending upon the actual development of facilities.

**Minimum Generation Limits During Light Load Conditions**

Large additions of wind generation may present a challenge in managing the baseload generation fleet output for the day-ahead commitment. For example, system demand may fall below the minimum output of coal-fired plants. Because of the potential inverse relationship between wind generation production and system demand, the production curve dips below the minimum output levels of coal-fired generation during off-peak hours (some examples are shown by the white circles in Figure 7 below).

**Figure RFC-7: Simplified Operations Example**




Potential solutions to address this issue include turning off large baseload coal plants and, instead, use gas-fired generation to meet minimum demand periods. However, most coal-fired units have a substantial start-up time and high start-up costs. As dependence on gas increases, production costs may increase due to dispatching gas-fired generation before coal-fired generation. An alternative to turning off coal units is to curtail wind generation output. Minimal costs are associated with curtailing wind. However, if the wind generator is being used to meet a state-mandated Renewable Portfolio Standard (RPS), curtailment could result in a utility falling short of the requirement. Furthermore, plentiful wind energy periods are often concurrent with light-load or shoulder-peak system loading conditions, such as late evening during spring and fall seasons, such that the consequent amount of wasted wind energy is likely substantial.

### Increased Ramp Requirements and Out-of-Phase Ramping

Ramping is the increase or decrease of generation required to meet changes in load. Wind ramps can have an inverse correlation to daily load ramps resulting in the need for additional reserves to support ramp. As more wind generation is added to the system, the amplitude and direction of ramping requirements are expected to increase. Figures 8 below plots the real-time actual system information from the 2008 peak week (July 27, 2008 through August 2, 2008) to show the relationship between wind levels and ramp characteristics. Figure 9 displays the 2017 summer peak projected ramp characteristics obtained by escalating the 2008 peak wind and demand levels to the projected 2017 levels, with no additional diversity considered as a conservative measure.

**Figure RFC-8: Real-Time Ramp Requirement for RFC**
**July 27, 2008 – August 2, 2008**

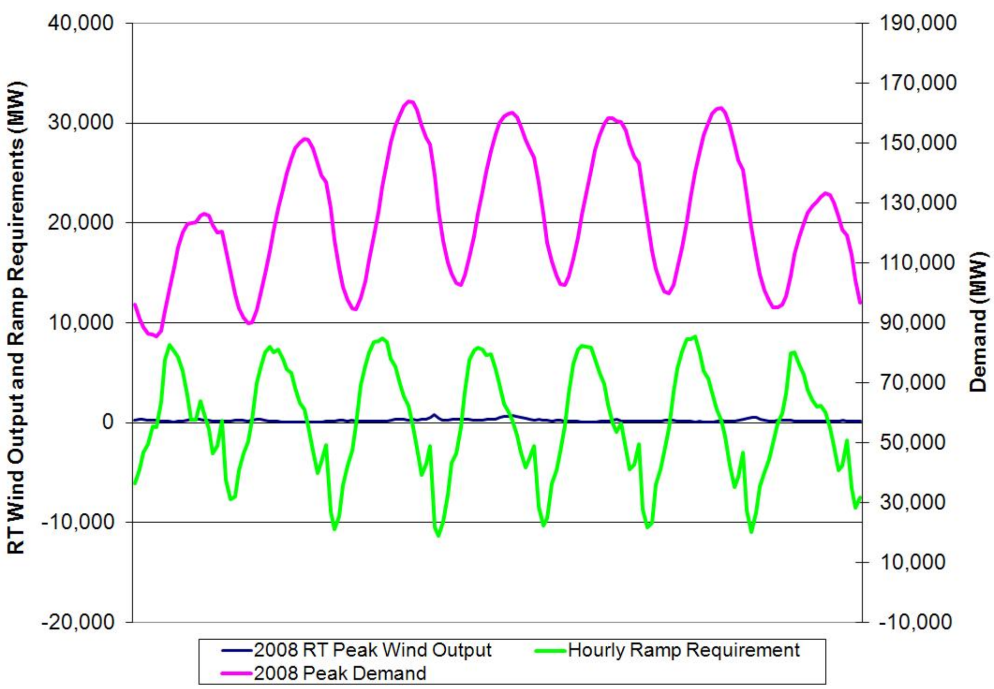


**Figure RFC-9: Projected 2017 Ramp Requirement for RFC Using Data from Figure 7**

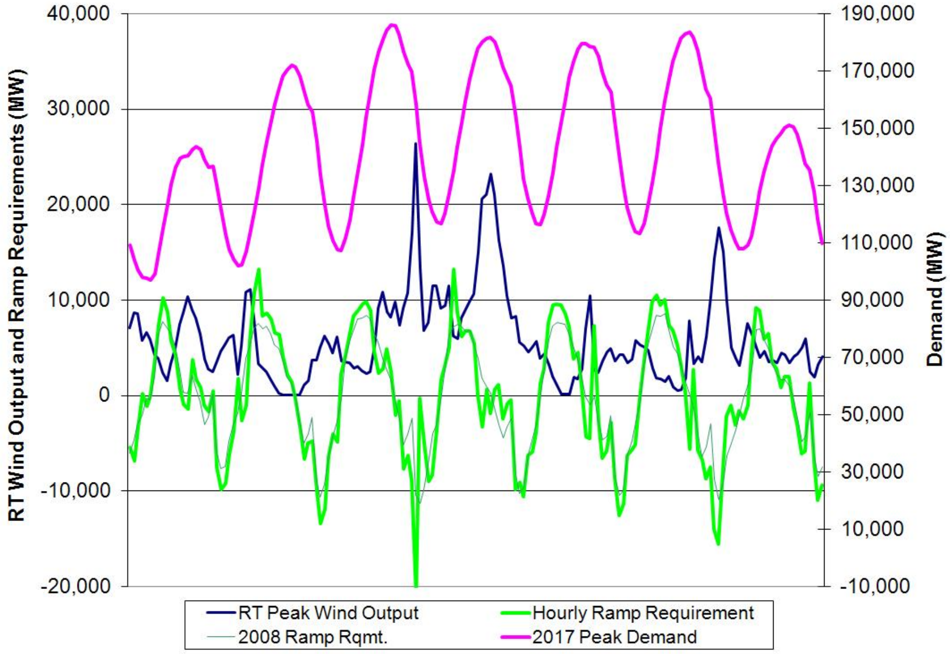



Table RFC-3 summarizes the differences in ramp requirements between the 2008 peak week and the 2017 projected peak. Both the amplitude (average positive/negative ramp and maximum positive negative ramp) and volatility (number of sign changes) increase with the additional level wind generation. These changes indicate that operators may need to more closely monitor the system.

**Table RFC-3: RFC Weekly Ramp Requirement Comparison**

| | 2008 | 2017 |
|---|---|---|
| Average Negative Ramp (MW) | -4534 | -5610 |
| Average Positive Ramp (MW) | 4691 | 5330 |
| Number of Hours Positive | 82 | 86 |
| Number of Hours Negative | 86 | 82 |
| Number of Sign Changes | 16 | 32 |
| Maximum Positive Ramp (MW) | 8600 | 13238 |
| Maximum Negative Ramp (MW) | -11329 | -20860 |

### Need for Accurate Day-Ahead and Hourly Wind Forecasting

Predicting, with reasonable confidence, the output level of wind generation for a future time period (e.g. day ahead, hour ahead, etc.) is limited, at best. Because wind generation is driven by the same physical phenomena as weather, the uncertainty associated with the prediction of wind generation level at some future hour (even the next hour) may be significant. For example, in February 2008 in Texas, the forecast quantity of wind generation output could not be met due to an unexpected drop in the wind. As wind generation penetration levels increase, the forecast accuracy becomes essential to operate a reliable system. Additionally, accurate wind forecasts and timely updates are necessary in order to incorporate wind generation into the Day Ahead markets.

The Midwest ISO uses a centralized wind forecasting program in its market footprint to capture reliability and economic aspects of integrating wind into the Day Ahead and Real Time Markets. The program uses a Multi Numerical Weather Prediction (NWP) model to come up with its best estimate for each node, zone, Region and Midwest ISO total. PJM also is implementing an RTO-wide wind forecasting program. Also, because of the larger system size of RTOs, the overall effects of a sudden drop in wind generation may be minimal.

### Need for Additional Operating Reserves

Contingency reserves may need to increase with large quantities of wind generation online. This is due to the variability of wind generation output, which may result in an inadequate amount of contingency reserves. This concern would dictate that the operating entity take a conservative stance, and therefore may require more contingency reserves be available in the day-ahead market. The variability and ramping characteristics of wind turbine output may also require additional spinning and contingency reserve margins, both positive and negative. The precise amount changes day to day depending on the quality of Regional wind prevalence. These factors would dictate that day-ahead ancillary service markets must be closely coordinated with wind forecasts and real-time monitoring of wind output.

### Acceleration of Baseload Unit Retirements

Existing baseload generating units provide dependable operational reserve margins and reduce market price volatility, precisely the characteristics needed in an environment striving to accommodate large-scaled wind power integration. Many baseload units are located where their dynamic reactive capabilities are also crucial to voltage regulation and local system reliability. However, when wind generation penetration reaches a level where many of these older and less efficient baseload fossil-fueled units become sporadically dispatched day-in and day-out, their owners may contemplate an accelerated retirement of these units. This accelerated retirement may increase the need for additional operating reserves, as mentioned above.

## Reliability Assessment Analysis

A resource adequacy assessment of the reference and *Scenario Cases* would demonstrate that Regional reliability criterion is expected to be met since the JCSP study included an assumed amount of capacity additions necessary to meet the reserve criterion as determined in studies conducted by PJM and MISO for their respective RTOs. The reserve margins in both the reference and *Scenario Cases* are 23 percent. These reserves do not require a reliance on external resources to satisfy Regional demand. They are also sufficient to satisfy demand levels above the base 50/50 demand forecast.

However, there would be an expected increase in net imports, as the amount of renewable energy needed to satisfy Renewable Portfolio Standards (RPS) is likely to create a need to import wind and other renewable resources.

Generating unit retirements between the *Reference Case* and the *Scenario Case* are identical. However, as mentioned in the operations section above, when wind generation penetration reaches a level where many of these older and less efficient baseload fossil-fueled facilities become sporadically dispatched day-in and day-out, owners may contemplate an early retirement of those baseload facilities.

The JCSP study did not address the issue of deliverability since this was a first-ever conceptual-type study. Both MISO and PJM have detailed deliverability criteria and conduct studies on a regular basis to determine the deliverability of generation resources. These detailed deliverability studies would need to be performed prior to the new generation coming on-line in the future.

It is assumed that new wind facilities that may be integrated into the system would comply with FERC Order 660-1A, which addresses the need for low-voltage ride-through capabilities and reactive power capabilities of individual wind turbines. In both the Midwest ISO and PJM, reactive power analysis is one integrated part of every individual Generation Interconnection System Impact Study. No wind plant can be granted interconnection services without mitigating the incremental reactive support problem it would cause. The PJM Ancillary Service Market, the Midwest ISO Ancillary Service Market and the Midwest Contingency Reserve Sharing Group provide financial incentives and legal obligations to ensure that the entire Midwest ISO system has adequate frequency response support in both the short term and long term. The Midwest ISO believes that wind forecast accuracy is critical to minimizing unexpected ramps in wind production which in turn would minimize the requirement for additional reactive and frequency support requirements. Generator characteristics would be reviewed to identify more responsive units, which also may alleviate reactive or frequency response issues.

The Midwest ISO and PJM are actively working with their stakeholders to determine the best solution to be able to incorporate large amounts of wind. Accurate wind forecasts for the Day Ahead market process and accurate and timely updates during the operating day would need to occur in order to incorporate wind generation into the Day Ahead market. Equitably allocating costs for reserve sharing would need to be developed, also. In addition, it may be necessary to change operating reserve requirements, regarding the amount of operating reserves, the type of operating reserves, and the deployment of operating reserves.

Fuel supply vulnerability was not analyzed in these cases. There is no significant change expected to the resulting fossil fuel mix as a result of the *Scenario Case*. The significant increase

(25,600 MW) in the amount of wind generation is coupled with a decrease (9,000 MW) of coal-fired generation and an increase in gas-fired combustion turbine capacity (3,500). However, the change in fossil fuel types is less than 10 percent for coal and less than 5 percent for gas.

### Other Region-specific issues that were not mentioned above

In order to ensure Renewable Portfolio Standards are met, it is likely that the wind turbines installed may exceed the nameplate amounts in this assessment to allow for annual variations in wind output and contingent coverage of lost generation during light demand periods. Additionally, it is not clear whether the manufacturing infrastructure exists needed to build the number of wind turbines represented in the *Scenario Case* by 2018.

### Region Description

*RFC currently consists of 47 Regular Members, 22 Associate Members, and 4 Adjunct Members operating within 3 NERC Balancing Authorities (MISO, OVEC, and PJM), which includes over 350 owners, users, and operators of the bulk-power system. They serve the electrical requirements of more than 72 million people in a 238,000 square-mile area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. The RFC area demand is primarily summer peaking. Additional details are available on the RFC website (*http://www.rfirst.org*).*

# SERC

### *Southeast Generation Fuel Shift Analysis*

## Introduction

Detailed discussion of the 2008 *Long-Term Reliability Assessment Reference Case* (*Reference Case*) for the comparisons presented here can be found in the introductory sections of this report. Because there is little or no penetration of type of resources offered in the Scenario #1 option of the NERC Scenario Analysis in the SERC Region, the utilities in the SERC Region opted for Scenario #2 (a scenario of the Region's choosing). The SERC Region selected a scenario which significantly impacts supply mix in the SERC Region in 2019 by adding significant amounts of carbon neutral generation as indicated in table 1 below. The SERC Long-term Study Group (LTSG) conducted this study to evaluate future performance of the interconnected electric transmission systems within the SERC Region for the 2019 summer peak season. This study was initiated in July 2008, at the direction of the SERC Regional Studies Steering Committee (RSSC), as part of a continuing effort to:

- Accomplish the objectives of the various reliability agreements among SERC member systems by examining the resulting transfer capability, and
- Respond to the data request of NERC for a Long-term Reliability Assessment *Scenario Case* to supplement the *Reference Case*.

The primary focus of this scenario is the addition of substantial generation (both nuclear and fossil but primarily nuclear) beyond the *Reference Case*; over 13,000 MW to selected points in the Region.

The SERC Reliability Review Subcommittee (RRS) proposed and received approval by the NERC Planning Committee (PC) to evaluate potential Southeast Generation Expansion as the Region's *Scenario Case*. The prospective generation plants within the SERC Region would introduce large amounts of capacity in only a few sites on the system (resulting in a lumpiness effect), requiring some bulk power transmission expansion. While the local area impact of each plant would be captured by the required System Impact Studies to be performed by the respective Transmission Providers to which these plants would be interconnected, joint-studies in the future are expected to evaluate system reliability impacts of all the proposed and prospective plants simultaneously.

**Study Procedure**

This study utilizes a power flow model developed by the SERC study group representatives to include best-available representations of the projected 2019 summer season at the time of this study. The power flow study model was derived from the 2019 summer season SERC case (LTSG19S), which was created during the SERC Data Bank Update by SERC utilities the week of June 2-6, 2008. Typically, the aforementioned changes are either budgeted or planned/conceptual facilities with in-service dates during or after the summer of 2008.

The study results were obtained by use of PTI's MUST and PSS/E programs. The base case, linear runs, and AC verification were performed by TVA and the report was assembled by Associated Electric Cooperative, Inc.

### Demand

There were no differences between the *Reference Case* and *Scenario Case* relative to weather, economic assumptions, growth rate or load variability. Additionally there were no differences in controllable demand response reducing peak demand - i.e. interruptible demand; direct control load management; critical peak pricing with control; load as a capacity resource, etc.

### Generation

The amount of capacity resources expected to be in-service by 2019 in the *Reference Case* is 232,027. The *Scenario Case* results in incremental 13,112 MW of installed resources (an increment of approximately 6 percent) in accordance with Table 1 by fuel type. All incremental resources are conventional resources.

**Table SERC-1: SERC Region Generation by 2019 by Fuel Type MW**

| Resource Type | *Reference Case* | *Scenario Case* | Difference |
|---|---|---|---|
| Nuclear | 38,041 | 50,500 | +12,459 |
| Fossil | 169,158 | 169,436 | +278 |
| All others | 24,829 | 25,204 | +375 |
| Total | 232,028 | 245,140 | +13,112 |

The assumptions pertaining to when resources are added over the entire ten-year time frame are not developed, as this analysis is a single year analysis for 2019. Generation added for the 2019 study was distributed among four of the five SERC subregions as follows:

**Table SERC-2: SERC Region 2019 Additional Generation by Subregion by Fuel Type MW**

| Resource Type | Central | Delta | Gateway | VACAR | Total |
|---|---|---|---|---|---|
| Nuclear | 2,426 | 3,288 | 1,706 | 5,039 | 12,459 |
| Fossil | 278 | 0 | 0 | 0 | 278 |
| All others | 375 | 0 | 0 | 0 | 375 |
| Total | 3,079 | 3,288 | 1,706 | 5,039 | 13,112 |

There are no differences in variable (i.e. wind, solar, etc.) resources between the *Reference Case* and the *Scenario Case*; however much of the new generation is conventional carbon neutral technology.

There are no differences in Biomass (wood, wood waste, municipal solid waste, landfill gas, and ethanol) generation projects between the *Reference Case* and the *Scenario Case*.

The process for selecting the incremental planned and proposed resources included in the change case was based on input of utilities in the SERC Region for prospective projects beyond those formally announced as of June 2008. The projects are largely co-located with existing facilities. A majority of the new resources being conventional and for the most part nuclear. Any impacts of carbon sequestration on fossil generation (i.e. derates) were not considered.

### Capacity Transactions on Peak and Assumed Transfers

There are no differences in capacity transactions on peak due to the availability of additional generation resources. No SERC-wide economic dispatch model was run because no single entity performs economic dispatch assessments across the entire SERC footprint at this time and this level of effort was not within the scope of the scenario analysis request from NERC.

This study incorporates projected loads and base transfers as well as the interconnected transmission network configuration and generation facilities of SERC member systems currently identified for operation by the 2019 summer peak season. IPP generating facilities without a signed interconnection agreement are not modeled as being in-service for the *Reference Case*.

The amount of resources external to the SERC Region used by utilities in the SERC Region would likely decrease due to the incremental resources added within the Region in this scenario.

### Transmission

New bulk transmission line facilities upgrades and new lines necessary to integrate the 13,112 MW of incremental generation resources outlined in section 1 is presented in summary in the following table.

**Table SERC-3: SERC Region Transmission Projects by Facility Type - Miles**

| **Transmission Facility Type** | ***Reference Case***[94] | ***Scenario Case***[95] |
|---|---|---|
| New Lines | 2,429 | 547 |
| 161 kV | 0 | 80 |
| 230 kV | 1,644 | 188 |
| 345 kV | 338 | 0 |
| 500 kV | 447 | 279 |
| Upgrades Lines | 0 | 170 |
| 230 kV | 0 | 59 |
| 500 kV | 0 | 111 |
| Total | 2,429 | 717 |

No new bulk transmission transformer facilities necessary to integrate the incremental generation were identified at this time although when the planning for these facilities is undertaken there would likely be new transformer additions.

There were no new FACTS, SVC or similar technology projects assessed in this scenario.

[94] This represents the cumulative period result from the *Reference Case*.
[95] Single year assessment for 2019.

**Transfer capability assessment**

This study assesses the strength of the SERC interconnected network by determining its ability to support power transfers, which are incremental to the base transfers. Transfer capabilities are calculated using a linear analysis technique in accordance with accepted practice as defined by NERC in the document *Transmission Transfer Capability*, dated May 1995. Both the Normal Incremental Transfer Capabilities (NITCs) and First Contingency Incremental Transfer Capabilities (FCITCs) are used in this report. For conditions other than those modeled, response factors can be used to approximate incremental transfer capabilities.

For the subregional transfers, an AC power flow at the transfer test level was conducted with the first reported "hard" limit contingency in effect to check for voltage constraints associated with the transfer. Compliance with the NERC Reliability Standards (Table I of NERC Reliability Standard TPL-001 and TPL-002) was assessed with an AC Contingency Analysis (PSS/E activity ACCC); to test for voltage violations and thermal overloads on the power flow study model for all submitted contingencies.

Calculated transfer capabilities in this report are not extrapolated beyond the study transfer test levels. Study transfers are simulated by increasing generation in one area while simultaneously decreasing generation in another area. When necessary, control area loads are reduced in the exporting system in order to provide sufficient capacity for modeling desired levels of transfer. Monitored circuits that are not significantly affected by the power transfer are not generally reported. Variations in local conditions typically have a more profound effect on these facilities than do the power transfers under investigation. In general, limiting facilities having a transfer response calculated to be less than 3.0 percent are omitted from the reported results.

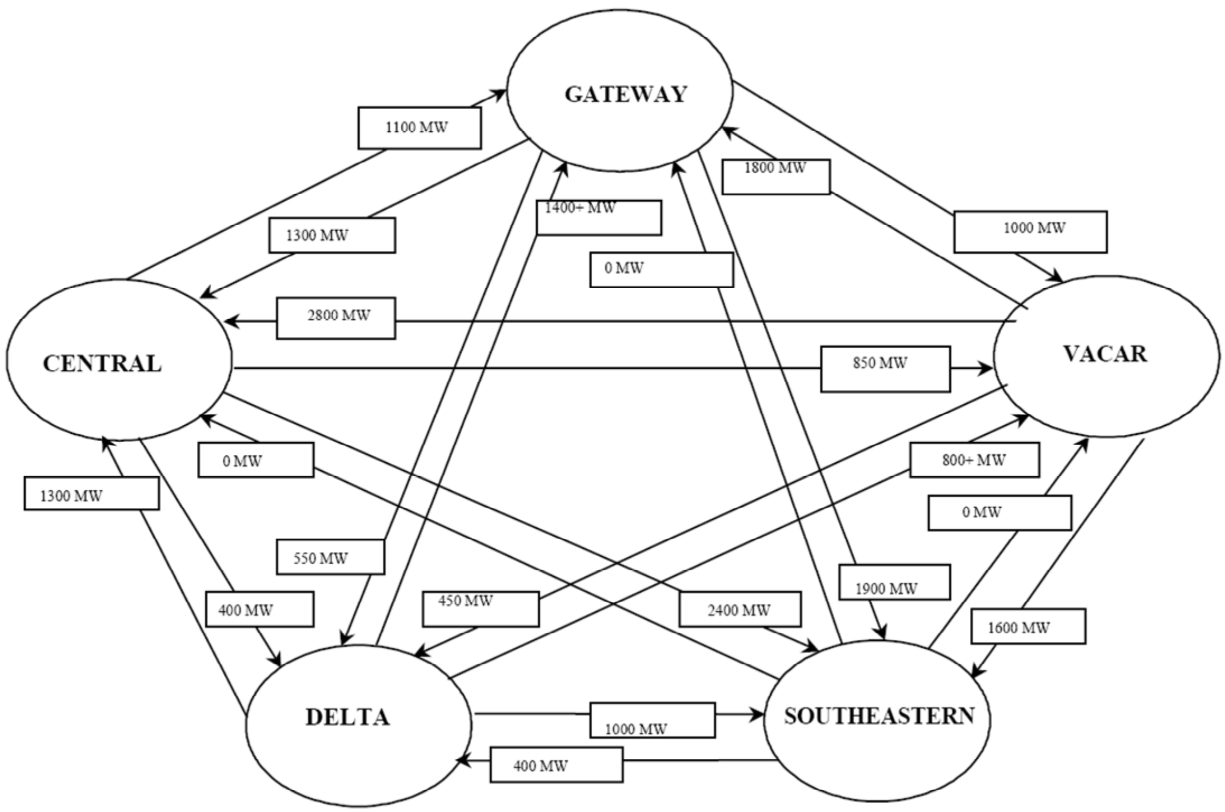
The transfer capabilities identified in this report are non-simultaneous, and based on computer simulations of interconnected electric system operations under a specific set of assumed operating conditions for the 2019 summer peak season. Each simulation represents a single "snapshot" of the operation of the interconnected systems based on the projections of many factors that included expected customer demands, generation dispatch, scheduled maintenance, interconnected transmission network configuration, and the electric power transfers in effect among the interconnected systems. In the real-time operation of the interconnected electric systems, many of these factors are continuously changing. As a result, the electric power transfers that can be supported on the transmission systems would vary from one instant to the next. For this reason, the transfer capabilities reported in this study correspond to a specific set of system conditions for the interconnected network and can be significantly different for any other set of system conditions. The transfer capabilities reported in this study should be viewed as *indicators* of system capability.

As a measure of projected transmission system performance for the 2019 summer season, this study utilizes assessments of incremental transfer capabilities among the SERC member systems. This study also assessed performance as required by NERC Reliability Standards for Transmission System Performance.

The bubble diagrams that follow depict the subregional First Contingency Incremental Transfer Capability (FCITC) for the *Reference Case* (Figure 1) and the *Scenario Case* (Figure 2). FCITC values reported for power transfers between the Central, Delta, Gateway, Southeastern and VACAR subregions indicate incremental transfer capabilities (above base transfers modeled) ranging from 0 MW to 4,000+ MW. It should be realized that several limits are valid only with the completion of planned facility upgrades. If the new facilities are not built, the actual transfer limits may be lower. AC power-flow verification revealed no voltage constraints for the tested subregional transfers.

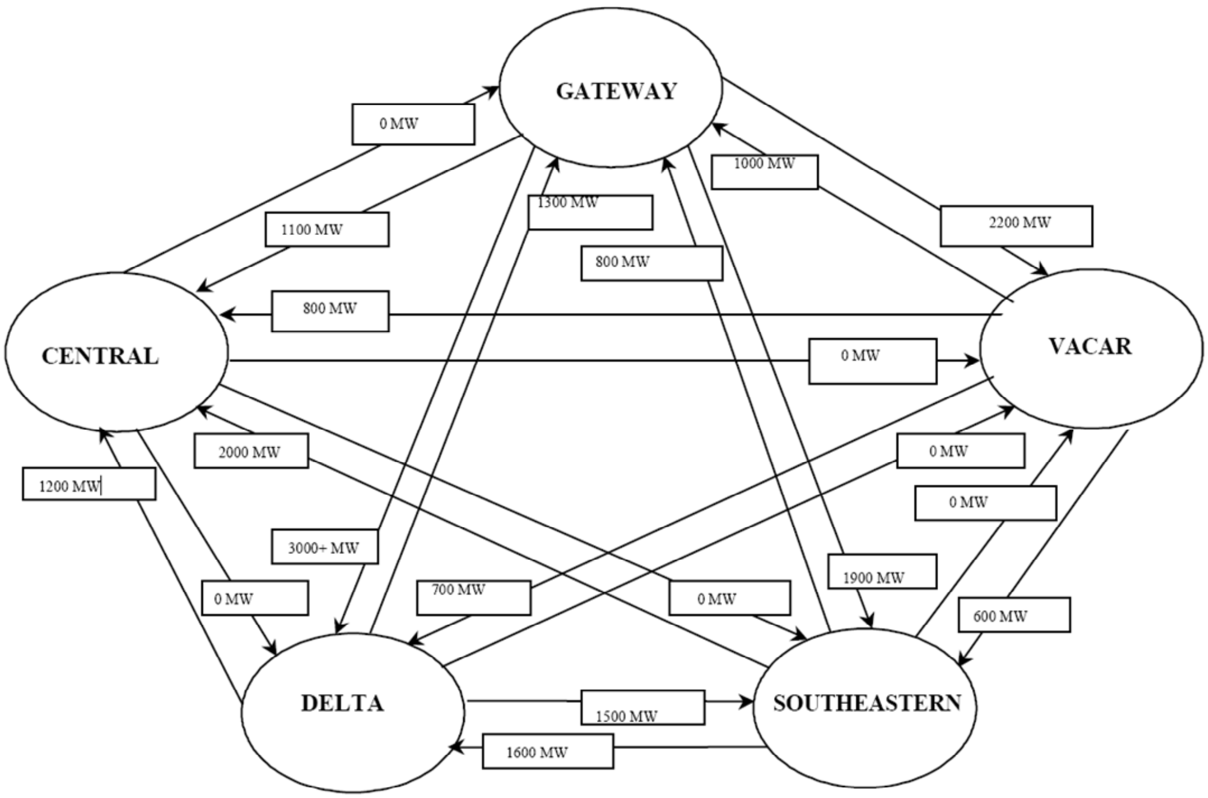
**SUBREGIONAL SUMMARY OF INCREMENTAL TRANSFER CAPABILITIES FIRM CONTRACTS AND FIRM NATIVE LOAD RESERVATIONS SERC LTSG 2019 Summer Future Year Study**

**Figure 1**



**SUBREGIONAL SUMMARY OF INCREMENTAL TRANSFER CAPABILITIES FIRM CONTRACTS AND FIRM NATIVE LOAD RESERVATIONS SERC LTSG 2019 Summer Future Year Study SCENARIO CASE**

**Figure 2**




The foregoing bubble diagrams provide an assessment of the subregional incremental transfer capabilities and the *Reference Case* and *Scenario Case* Actual transfer capability levels vary as a function of transfer direction, other transfer activity, generation dispatches, and load levels.

The assessment of the interconnected SERC transmission systems within SERC applying NERC Reliability Standards TPL-001 and TPL-002, for anticipated 2019 summer peak conditions, included the simulation of single contingencies throughout the SERC Region and the evaluation of the impacts of these contingencies on both individual and neighboring systems. The coordinated contingency screening activity encompassed in this assessment has identified no significant impacts on neighboring systems for local transmission contingencies tested.

Individual system plans are in various stages of implementation and only for the purposes of this scenario analysis are expected to be completed by the 2019 summer period.

**Transfer Analysis Comparison**

For the subregional transfers, an AC power flow at the transfer test level was conducted with the first reported “hard” limit contingency in effect to check for voltage constraints associated with the transfer. Calculated transfer capabilities are not extrapolated beyond the study transfer test levels, are non-simultaneous, and based on computer simulations of interconnected electric system operations under a specific set of assumed operating conditions for the 2019 Summer peak season.

Each simulation represented a single “snapshot” of the operation of the interconnected systems based on the projections of many factors that included expected customer demands, generation dispatch, scheduled maintenance, interconnected transmission network configuration, and the electric power transfers in effect among the interconnected systems. In real-time operation of the interconnected electric systems, many of these factors are continuously changing. As a result, the electric power transfers that can be supported on the transmission systems would vary.

### Operational Issues

Although it is difficult to project actual operational issues from a high level scenario analysis such as this, a few potential issues come to mind which, while not analyzed here are listed for future consideration. Operating guides are likely needed by 2019. The potential differences between the *Scenario Case* and the *Reference Case* which would require future evaluation include the following:

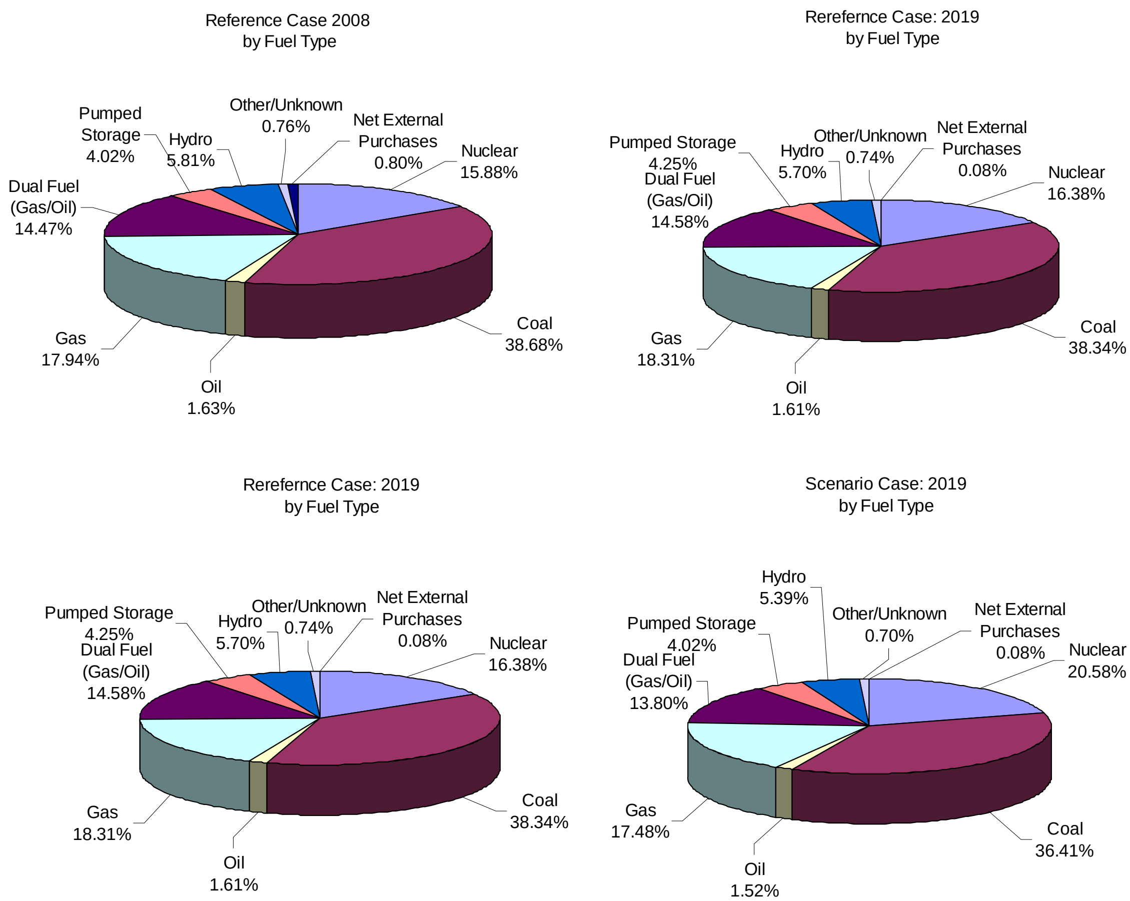
- As unit sizes increase with the new capacity additions, requirements for spinning reserve are likely to increase. Operation changes are inevitable.
- As generation is more concentrated at existing sites, common mode failures and multiple contingency losses would need to be thoroughly investigated as part of the planning process under NERC Standards in effect at the time.
- As more base load generation is added, its capability to follow load would need to be understood. At present it is expected that (based on vendor representations) new base load nuclear plants would have greater load following capability than in the past.

### Reliability Assessment Analysis

The reserve margin of the *Reference Case* in 2019 is 4.1 percent and of the *Scenario Case* is 9.7 percent. Neither would meet the target margin of 15 percent as set out by NERC, however for this scenario analysis it is instructive to see how we might achieve a better outcome. For a 200,000 MW load system with a little less than 2 percent growth per year, we need approximately 3,000 to 4,000 MW per year to keep pace. At this point in time, the announced plans in the *Reference Case* do not, hence deterioration in resource margin over the period. The amount of resources internal to the Region increase in the *Scenario Case*. SERC does not perform a system-wide resource adequacy study using probabilistic methods at this time.

The amount of resources internal to SERC relied upon to meet state and utility resource requirements increases in the *Scenario Case*. Therefore, the amount of resources external to the Region being relied on for reliability purposes decreases.

**Figure SERC-5: Fuel-Mix Comparisons**




The fuel mix comparisons for 2019 are shown above. Note that even with a substantial generation addition, the 2019 nuclear component increases by 4 percent.

No additional retirements were considered in this analysis except for those reported as part of the 2008 *Reference Case*.

This study provides extensive comparative information regarding transfer capability (FCITC and NITC) in the transmission section above. The Transmission additions were selected as the minimum needed to integrate the generation proposed. Deliverability is generally resolved by these transmission additions however details planning is required to verify

There is no incremental wind or biomass introduced in the study. While over time we may see more biomass and other renewables, the current view is that the wind resources in the Southeast (except for the Gateway subregion and certain offshore areas of the eastern SERC states) is generally not economic to develop. As such, there would be no need to address the variability issues that would come with substantial wind generation penetration in the SERC Region.

There would be no additional changes needed to market structures or ancillary service requirements in the SERC Region for the reliable operation of the *Scenario Case*.

With the addition of significant new base load facilities, the exposure to disruption of fuel supply due to traditional coal and gas fuel supply system (pipeline, rail) vulnerabilities is generally reduced. The fuel mix changes are demonstrated in figures 5 and 6 above.

### Region Description

*The SERC Region is a summer-peaking Region covering all or portions of 16 central and southeastern states[96] serving a population of over 68 million. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles. SERC is the Regional Entity for the Region and is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply system. SERC membership includes 63 member-entities consisting of publicly-owned (federal, municipal and cooperative), and investor-owned operations. In the SERC Region there are 30 Balancing Authorities and over 200 Registered Entities under the NERC functional model.*

*SERC Reliability Corporation serves as a Regional Entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. The SERC Region is divided geographically into five subregions that are identified as Central, Delta, Gateway, Southeastern, and VACAR. Additional information can be found on the SERC web site (www.serc1.org).*

[96] Alabama, Arkansas, Florida, Georgia, Iowa, Illinois, Kentucky, Louisiana, Missouri, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia

# SPP

## Introduction

The comparison of *Reference Case* and *Scenario Case* is based on data for the year 2018 from the *2009 Long-Term Reliability Assessment* (LTRA) assessment.

The JCSP offers a conceptual Regional transmission and generation system plan for a large portion of the Eastern Interconnection in the United States, developed with the participation[2] of most of the major transmission operators in the Eastern Interconnection. This initial effort looks at two scenarios that expand transmission and generation opportunities between 2008 and 2024: a Reference Scenario and a 20 percent Wind Energy Scenario in support of the U.S. Department of Energy's (U.S. DOE) Eastern Wind Integration and Transmission Study.

The JCSP used common economic and system topology assumptions to characterize most of the Eastern Interconnection into a single multi-regional analysis, rather than through a parallel, Region-specific analysis.

Although the JCSP and successor efforts like Eastern Integration Planning Collaborative (EIPC) or Eastern Wind Integration and Transmission Study (EWITS) can help improve bulk power system planning in the Eastern Interconnection, parallel efforts would be needed to turn those plans into reality. Although many new generation and transmission investments are moving forward, other investments are constrained due to continuing uncertainties about the nation's policies regarding carbon regulation, renewable development policies, and super-regional cost/benefit allocation for projects that span multiple Regions. More clarity about these policy issues would facilitate new bulk power system investments needed to turn infrastructure plans into reality and make inter-regional and interconnection-wide transmission expansion planning effective.

## Demand

There is no difference between the Scenario and *Reference Case* regarding weather, economic assumptions on which the load forecast is derived, or projected dispatchable, controllable demand response. The *Reference Case* energy demand forecasted for 2018 is 240,513 GWh, and the amount of new energy forecasted by the JCSP study for 2018 is 28,542 GWh. The total forecasted energy demand combining the *Reference Case* and *Scenario Case* is forecasted to be 269,055 GWh. The projected interruptible demand, direct control load management, and other factors remain unchanged in the *Scenario Case*.

## Generation

SPP's *Scenario Case* uses the year 2018 and reports 20 percent wind energy in the SPP footprint above and beyond the *Reference Case*. The existing wind nameplate capacity of the *Scenario Case* is 1,611 MW, with 532 MW reported towards capacity on-peak. The planned wind nameplate capacity is 2,808 MW with 926 MW reported towards capacity on-peak. There is a conceptual wind nameplate capacity of 4,000 MW, of which 1,823 MW are expected to be reported towards capacity on-peak. The existing, planned, and conceptual wind nameplate capacity form the *Scenario Case* total of 8,419 MW. The capacity additions of conventional

resources that are planned to come on-line in 2018 amounts to 4,292 MW. These additional capacity additions were taken from the 2009 Long Term Reliability Assessment.
The generation mix of the *Scenario Case* and the *Reference Case* for 2018 includes wind, nuclear, hydro, coal (steam), oil (steam), oil (combustion turbine), gas (combustion turbine), oil (combined cycle), and a combination of other resources.

For Future and Conceptual Capacity resources, SPP uses the Generation Interconnection (GI) and Transmission Service Request (TSR) study process as defined within the SPP Tariff.[97]

According to the SPP Tariff, at the time the Interconnection Request (IR) is submitted, an Interconnection Customer must request either Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS); any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. The Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades would be completed.

### Capacity Transactions on Peak

Approximately 1 percent of SPP's capacity margin depends on purchases from other Regions. Transactions for 2018 are 692 MW purchased from other Regions. These purchases are considered firm transactions; 150 MW is firm delivery service from WECC, administered under Xcel Energy's Open Access Transmission Tariff.

SPP has a total of 786 MW of firm sales, which includes firm generation and transmission to Regions external to SPP. There are no known issues with the deliverability of imports or exports based on existing transmission.

SPP members, along with neighboring members including Entergy and others in the SERC Region, have formed a Reserve Sharing Group. Members of this group receive contingency reserve assistance from other SPP Reserve Sharing Group members. SPP's Operating Reliability Working Group sets the minimum daily contingency reserve requirement (approximately 1,600 MW) for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group maintains a minimum first contingency reserve equal to the generating capacity of the largest unit or transmission path scheduled to be on-line.

### Transmission

The JCSP study identified several new transmission projects for the SPP Region. These projects are needed to integrate an additional 20 percent wind into the Region. None of these transmission projects have an expected in-service date, as they are still considered conceptual. These projects will be incorporated into the SPP Integrated Transmission Plan (ITP) in 2010, and will then be assigned in-service dates as needed for reliability or economic reasons. The following projects are included in either the JCSP, the SPP Transmission Expansion Plan's 10 year reliability assessment, or the Balanced Portfolio of economic upgrades:

[97] http://www.spp.org/publications/SPP_Tariff.pdf

| Table SPP-1: Projected Transmission Additions | | | | |
|---|---|---|---|---|
| **Transmission Project Name** | **Voltage (kV)** | **Length (Miles)** | **In-Service Dates** | **Description/Status** |
| Tuco-Potter | 765 | 97 | N/A | Conceptual |
| Potter-Hitchland | 765 | 88 | N/A | Conceptual |
| Hitchland-Finney** | 765 | 100 | N/A | Conceptual |
| L.E.S.-Muskogee** | 765 | 185 | N/A | Conceptual |
| Tuco-L.E.S.** | 765 | 210 | N/A | Conceptual |
| Mooreland-Commanche** | 765 | 54 | N/A | Conceptual |
| Commanche-Spearville** | 765 | 51.2 | N/A | Conceptual |
| Spearville-Knoll* ** | 765 | 76 | N/A | Conceptual |
| L.E.S.-Elk City | 765 | 82.2 | N/A | Conceptual |
| Elk City-Mooreland | 765 | 72 | N/A | Conceptual |
| Hitchland-Mooreland** | 765 | 117 | N/A | Conceptual |
| Finney-Spearville** | 765 | 66 | N/A | Conceptual |
| Summit-Swissvale** | 765 | 104 | N/A | Conceptual |
| Swissvale-Iatan** | 765 | 51 | N/A | Conceptual |
| Knoll-Summit** | 765 | 98 | N/A | Conceptual |
| Lang-Wolf Creek | 345 | 24 | N/A | Conceptual |
| Commanche-Wolf Creek** | 765 | 203 | N/A | Conceptual |
| Wolf Creek- Lacygne** | 765 | 57 | N/A | Conceptual |
| Sedalia –Phill | 345 | 54 | N/A | Conceptual |

* These projects are included in the Balance Portfolio study, are proposed to be built at 345kV.
** These projects are included in the SPP's Extra High Voltage (EHV) study, and are proposed to be built at 765kV.

Along with the transmission lines listed above, several new transformer additions are included in either the JCSP or Balanced Portfolio:

| Table SPP-2: Projected Transformer Additions | | | | |
|---|---|---|---|---|
| **Transformer Project Name** | **High Side Voltage (kV)** | **Low Side Voltage (kV)** | **In-Service Date** | **Description/Status** |
| Tuco | 765 | 345 | N/A | Conceptual |
| Potter | 765 | 345 | N/A | Conceptual |
| Hitchland | 765 | 345 | N/A | Conceptual |
| Finney | 765 | 345 | N/A | Conceptual |
| Muskogee | 765 | 345 | N/A | Conceptual |
| L.E.S. | 765 | 345 | N/A | Conceptual |
| Mooreland | 765 | 138 | N/A | Conceptual |
| Commanche | 765 | 138 | N/A | Conceptual |
| Spearville | 765 | 230 | N/A | Conceptual |
| Knoll345 | 345 | 230 | N/A | Conceptual |
| Knoll765 | 765 | 345 | N/A | Conceptual |
| Elk City | 765 | 230 | N/A | Conceptual |
| Iatan | 765 | 345 | N/A | Conceptual |
| Summit | 765 | 345 | N/A | Conceptual |
| Swissvale | 765 | 345 | N/A | Conceptual |
| Lacygne | 765 | 345 | N/A | Conceptual |
| Wolf Creek | 765 | 345 | N/A | Conceptual |
| Sedalia | 345 | 161 | N/A | Conceptual |

Projects are identified by SPP through its Balances Portfolio and/or SPP Transmission Expansion Plan's 10 year reliability assessment.

One objective of the Balanced Portfolio and EHV Overlay study[98] is integrate wind and other efficient generation to serve load in the SPP footprint.

### Operational Issues

The variability of wind energy remains the key operating challenge within the SPP footprint. For instance, power output from wind generators typically peaks during the light load hours, and a large portion of wind generators would trip as a result of high- or low- wind situations. It would be critical for SPP to managing ramp rates and maintain adequate spinning reserve using fossil fuel units.

The SPP WITF (Wind Integration Task Force) is conducting and reviewing studies to determine the impact of integrating wind generation into the SPP transmission system, energy markets, and operations system. These impacts include both planning and operational issues. Additionally, these studies should lead to recommendations for the development of any new tools required for SPP to properly evaluate requests for interconnecting wind generating resources.

SPP is also participating in NERC's Integrating Variable Generation Task Force (IVGTF), in which specific recommendations will be made. SPP will participate in this effort of updating or developing reliability standards to reliably integrate variable generation resources into the bulk power system.

### Reliability Assessment Analysis

SPP's Reliability Criteria requires each member to sustain a 12 percent capacity margin or 13.6 percent reserve margin. For 2018, the forecast reserve margin from the 2009 *Reference Case* is 9 percent, compared to the 2009 *Scenario Case* capacity margin of 18.5 percent. The 18.5 percent *Scenario Case* capacity margin is based on assumptions in the JCSP, which uses a 33 percent capacity factor for existing and planned wind generation and a 45 percent capacity factor for conceptual wind generation. The rationale for this capacity factor is explained in the JCSP study assumption document.

The 9 percent capacity margin from the 2009 *Reference Case* does not take into account deliverable resources or 3,305 MW of conceptual resources that are forecast to be in-service in 2018.

There are no known unit retirements in the *Scenario Case* that would impact the SPP Region's reliability. There was no difference in the amount of deliverable resources for the SPP Region when the *Scenario Case* was compared to the *Reference Case*. There are no known potential retirements from new or emerging environmental regulations.

[98] SPP conducted Extra High Voltage (EHV) study which is similar to Balance Portfolio in 2008-2009 to examine economic projects in SPP footprint

SPP has not performed a specific Loss Of Load Expectation (LOLE) study with wind penetration for 2018. However, a sensitivity analysis was recently conducted with a wind penetration of approximately 2,500 MW in the western part of the SPP grid for year 2012. This LOLE analysis indicates a need for additional conventional resources in the local area and/or a transmission source into the western part of the grid.

The penetration of wind generation into the SPP footprint may have a significant impact on operations due to the variable nature of this type of supply-side resource. 28,542 GWh of incremental energy are projected to be injected into the Region by new wind resources. Several avenues are being explored to provide transmission outlets for this energy during the next ten years, such as the EHV Overlay Study, Balanced Portfolio, and JCSP. However, operational impacts to regulation and control performance caused by variable generation are still unknown. SPP anticipates the WITF study to be completed by 2009 and specific operational tools would be implemented in 2010.

SPP's is moving forward with day-ahead and ancillary service markets by 2012. The exact impact of the scenario discussed here on SPP's market structure or ancillary service requirements is yet to be determined.

There were no significant changes in fuel mix between the *Scenario Case* and the *Reference Case*, except for the integration of the 20 percent wind energy. SPP continues to monitor potential fuel supply limitations for conventional resources by consulting with its generation-owning and generation-controlling members at the beginning of each calendar year. There are no known infrastructure issues which could impact deliverability, as SPP is blanketed by major pipelines and railroads to provide an adequate fuel supply to the power generation sector. Coal–fired and natural gas power plants, which make up approximately 48 percent and 44 percent of total generation respectively, are required by SPP Criteria to keep sufficient quantities of standby fuel in case of deliverability issues. Because hydro-electric capacity is a small fraction of the overall capacity for the Region, run–of–river hydro issues brought about by extreme weather are also not expected to be critical.

## Region Description

*Southwest Power Pool (SPP) Region covers a geographic area of 370,000 square miles and has members in nine states: Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas. SPP manages transmission in eight of those states. SPP's footprint includes 26 balancing authorities and 47,000 miles of transmission lines. SPP has 54 members that serve over 5 million customers. SPP's membership consists of 12 investor–owned utilities, 11 generation and transmission cooperatives, 11 power marketers, 9 municipal systems, 5 independent power producers, 4 state authorities, and 2 independent transmission companies. Additional information can be found on www.spp.org.*

# WECC

## Introduction and Summary

The Western Electricity Coordinating Council (WECC) studied the effect of one scenario of 15 percent renewables generation (by energy) in the Western Interconnection in 2017. The scenario that was studied was not the only one that could have been constructed and other scenarios could lead to different specific results. The study, however, along with other efforts underway in WECC did lead to several general overall conclusions.

1. High levels of renewable generation, because of their spatial location relative to Western load centers, can lead to stresses on the capacity of the transmission system and the need to increase that capacity to deliver the generation to load.
2. High levels of variable renewable generation can raise significant operating challenges that can require new institutional arrangements and business practices in order to economically maintain the ability of Balancing Authorities (BA) to meet North American Electric Reliability Corporation (NERC) and WECC reliability standards.
3. While high levels of renewable generation per se do not raise adequacy issues, high levels of variable renewable generation, raise two kinds of adequacy issues.
    - First, it is important to evaluate how much variable generation can reliably be expected to contribute to system peak.
    - Second, high penetrations of variable generation can require significant amounts of flexible resources to integrate that variable generation into the grid. Only resources with the ability to ramp up and down quickly — such as hydro, combustion turbines, storage resources, and certain demand-side management resources — have the appropriate attributes to be able to integrate wind, solar photovoltaic, and other variable renewable resources into the grid.
4. High levels of renewable generation, typically with very low operating costs, would have a significant effect on generation and fuel use by those units typically on the margin (i.e., gas generation) in the Western Interconnection. This could raise issues of gas procurement and scheduling, though WECC was unable to study those issues. Natural gas supplies delivered through intra-state pipeline systems offer the greatest operating flexibility when such systems are connected to gas storage projects. The areas in WECC that plan to follow variable renewable output with gas-fired generation otherwise may need to have natural gas storage infrastructure built or inter-state pipelines would have to accept day-after or real-time schedule changes.

WECC and its members (utilities, state and provincial entities, independent generators, and others) are addressing the issues raised by these conclusions.

- WECC has an extensive study program ongoing under the guidance of the Transmission Expansion Planning Policy Committee (TEPPC). This work is performed in coordination with Western Subregional Planning Groups (SPG) and individual transmission providers to evaluate long-range needs for transmission expansion in the Western Interconnection. The coordination among the three levels of study efforts, interconnection-wide to individual transmission provider, and the relationship of these groups and study efforts to each other and to the providers' responsibilities under their Open Access Transmission Tariffs is described in a document posted on the WECC Web site.[99]

- In addition to the large number of past and ongoing operating issue studies being conducted by WECC members, WECC recently created the Variable Generation Subcommittee (VGS) to coordinate pertinent WECC study efforts and the dissemination of results (both WECC's and those of members) across the WECC membership. The VGS is modeled in part on the NERC Integration of Variable Generation Task Force (IVGTF) and has a mandate to address operating, planning and market issues related to variable generation in the Western Interconnection, and to interface and coordinate with the NERC IVGTF. The VGS is in its initial stages of developing work plans. A link to the VGS home page on the WECC Web site is provided below.[100]

- One of the tasks of the VGS Planning Work Group is to evaluate the various data sources available and studies already performed in order to provide guidance on the reliable capacity that is offered by the various kinds of variable renewable generation in the Western Interconnection, focusing particularly on wind generation. This would enable planners to evaluate the amount of other generation and demand-side resources that need to be put in place to ensure adequacy going forward.

- WECC does not at this time have a program to evaluate the impacts of gas displacement by large amounts of variable renewable generation on gas markets, gas procurement, and other issues raised for the natural gas system. However, the California Energy Commission (CEC) conducted a study in 2007 that examined the natural gas usage impacts of high penetrations of renewable in California, and the entire Western Interconnection.[101] The report found that with the high penetrations examined, sufficient natural gas usage reductions were predicted and that overall West-wide natural gas price declines could be expected.

  The CEC is conducting additional examinations of the impacts of high renewables on the natural gas system as part of the 2009 Integrated Energy Policy Report proceeding. A forthcoming CEC staff report suggests that a 33 percent renewable scenario on an interconnection-wide basis would reduce the predicted average annual natural gas use in the power generation sector by about 15 percent in the year 2020. This is a comparison to a *Reference Case* with renewable resources built out according to current requirements.[102]

### Background and Assumptions[103]

WECC performed two studies to respond to the transmission expansion and fuel use questions posed in the 2009 *NERC Long-Term Reliability Assessment* (*Scenario Case*). The base case was

[99] www.wecc.biz/committees/BOD/TEPPC/default.aspx
[100] www.wecc.biz/committees/StandingCommittees/JGC/VGS/default.aspx
[101] "Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Second Addendum." CEC, CEC-200-2007-010-AD2-SD. August 2007.
[102] "Impact of AB32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation." CEC, June 2009.
[103] Details supporting the narrative in this report are provided in the Attachment.

a study of the Renewable Portfolio Standard (RPS) required by the various Western states, and produced a weighted average renewable energy use of 8.8 percent. The *Scenario Case* was an extension of the base case and increased the renewable energy requirement to 15 percent. The existing resources, both conventional and renewable, were the same in both cases, but renewable resources were added to the different cases to satisfy the RPS requirements. These cases will be referenced in this report as the base case for the 8.8 percent RPS case, and *Scenario Case* for the 15 percent case.

WECC studied the 2009 *Scenario Case* with an hourly simulation of the year 2017 as part of the TEPPC 2008 study program.[104] This study used loads from the 2007 forecasts, since the 2008 forecasts were not available, though there were some updates from 2008 forecasts; one of them driven by the requirements of the hourly simulation. The load adjustments, described on the second page of “Attachment - WECC Study Results” (the Attachment), did not significantly affect the outcome of the study or the conclusions to be drawn from it. Generation was drawn from the data submitted for the 2008 *Long Term Reliability Assessment* (LTRA) data request, modified to develop a study case with 15 percent renewables penetration.

It is important to note that the *Scenario Case* was a constructed example of one geographic and renewables mix among a number of possible ways to meet one forecast of 2017 load levels. Just as the absolute levels of the load are not crucial to the conclusions that can be drawn from the study, neither are the exact specifications of the resource build out. The scenario was constructed by TEPPC to be a reasonable build out given the types of renewable generation currently being considered by Western entities, taking account of likely geographic diversity and resource quality available at different locations in the Western Interconnection.

The scenario was designed to be adequate, so it is not a test of the adequacy of a high renewables penetration scenario. Nonetheless, it was clear in the course of developing the scenario that adequacy issues were raised that need to be addressed, and WECC has developed a process for addressing them.

Moreover, since the modeling was in hourly time steps, the operating issues raised by variable generation, in particular wind since it is expected to make up a large percentage of the renewables that are developed in the Western Interconnection, were not apparent from the modeling. These issues are, however, known from other studies and from the ongoing operating experience of Western BAs that are already experiencing high renewables penetrations.

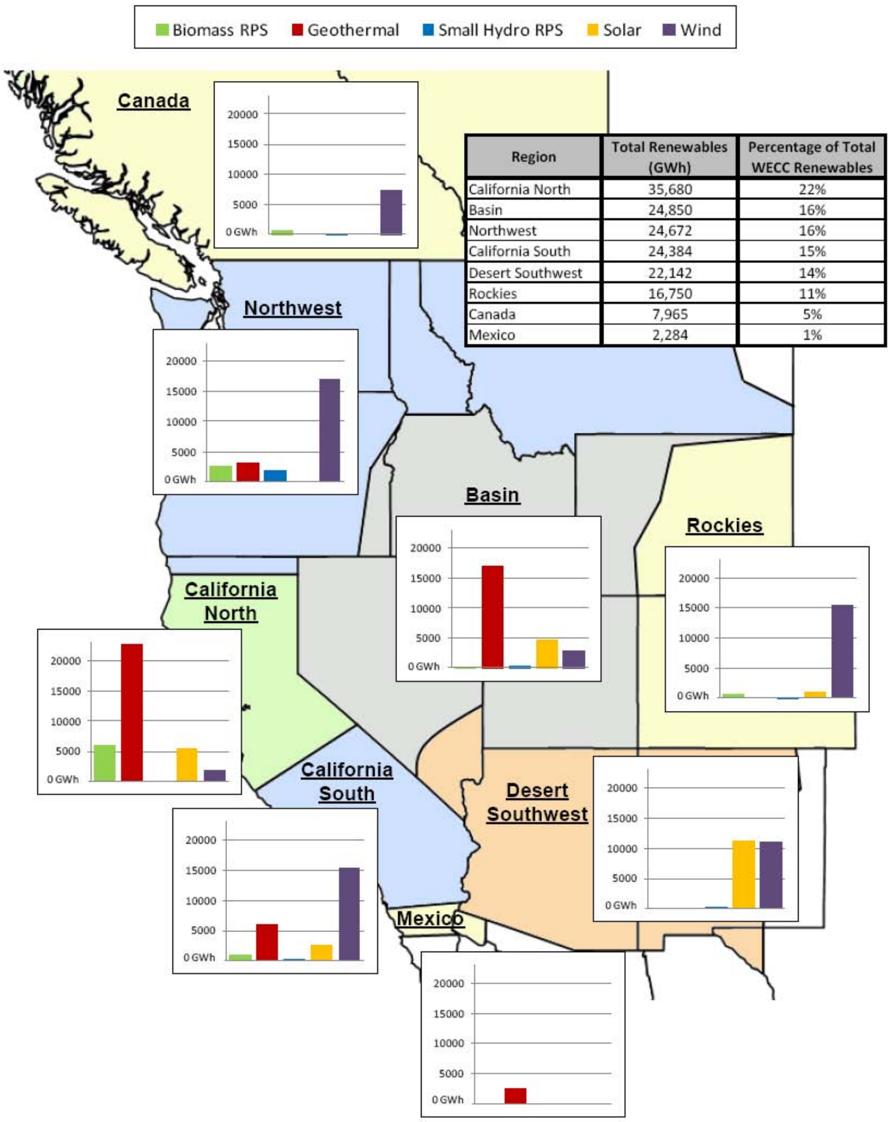
### Discussion

The renewable generation making up the 15 percent case was approximately 44 percent wind, 15 percent solar, 32 percent geothermal, and nine percent biomass. Much of this generation was sited relatively near major load centers, so that the transmission requirements though significant, were not entirely large, long-distance lines. For instance, much of the solar generation was located relatively near the major load centers of Phoenix and Southern California. The

[104] A security-constrained economic dispatch model using a DC load flow, PROMOD, was used for this study. The hourly simulation study done by TEPPC, which developed the transmission implications of the scenario, was supplemented by an analysis of the same data with a simplified version of PROMOD to develop other aspects of the study.

geographical distribution and relative magnitudes of the incremental renewable generation are indicated in Figure 1.

**Figure WECC-1 - LOCATION OF RENEWABLE RESOURCES BY WECC REGION**




| Region | Total Renewables (GWh) | Percentage of Total WECC Renewables |
|---|---|---|
| California North | 35,680 | 22% |
| Basin | 24,850 | 16% |
| Northwest | 24,672 | 16% |
| California South | 24,384 | 15% |
| Desert Southwest | 22,142 | 14% |
| Rockies | 16,750 | 11% |
| Canada | 7,965 | 5% |
| Mexico | 2,284 | 1% |

<u>Transmission Impacts</u>

The TEPPC study indicated which of the major paths in the Western Interconnection would face increased constraints with the addition of 15 percent renewable generation. The major paths that were studied are shown in Figure 2.

**Figure WECC-2 - LOCATION OF MAJOR WECC PATHS**


Western Electricity Coordinating Council

| # | Path Name |
|---|---|
| 36 | TOT 3 |
| 20 | PATH C |
| 31 | TOT 2A |
| 78&79 | TOT 2B |
| 35 | TOT 2C |
| 23 | FOUR CORNERS 345/500 kV |
| 49 | EAST OF COLORADO RIVER (EOR) |
| 46 | WEST OF COLORADO RIVER (WOR) |
| 15 | MIDWAY - LOS BANOS |
| 3 | NORTHWEST – CANADA |
| 66 | COI |
| 65 | PACIFIC DC INTERTIE (PDCI) |
| 8 | MONTANA – NORTHWEST |
| 1 | ALBERTA – BRITISH COLUMBIA |
| 14 | IDAHO – NORTHWEST |
| 37 | TOT 4A |

Generally the most heavily loaded paths or path elements, using a study metric of at least 20 percent of time loaded at least 99 percent of path rating, were the following:

- TOT 2C (Southwest Utah to Nevada)
- Four Corners 345/500 kV transformer
- Montana-Northwest Path
- Alberta-British Columbia

Using a metric of at least 10 percent of the time loaded at least 99 percent of path rating the most heavily loaded path added Northwest-Canada to the list of congested paths.

These paths are used in transfers from the wind generation areas of Montana, Wyoming, Colorado, and British Columbia in the North and Northeast parts of the interconnection to the major load centers along the Pacific Coast (Seattle to Southern California). Several other paths exhibited high loadings in the study simulations, generally related to transfers in the same direction as described above.

The Alberta-British Columbia path is a radial connection of Alberta to the rest of the interconnection and has known limitations. Alberta is one possible location for additional wind development that was not in the specific scenario studied. Additional wind development in Alberta would require either an upgrade to the Alberta-BC tie or additional connections between Alberta and the United States, several of which are under study for potential development.

There were several other paths that had high usages but were not necessarily tied to the increased renewables penetration under study. These included lines such as the Bridger West Path and the Intermountain Power Project DC line (not shown on the map), both constructed specifically to deliver the output of existing generation. Full details are given in the TEPPC report.[105]

TEPPC, the WECC committee that produced the transmission impacts study, is the Regional component of a three-tier cooperative planning process in the Western Interconnection that includes subregional planning groups and the individual transmission providers.

During 2008, TEPPC provided support to transmission providers and subregional planning groups in meeting the Regional planning requirements of FERC Order No. 890. The TEPPC Protocol was adopted by the WECC Board in 2008. The Protocol identifies a Western planning process and describes the use of a synchronized study plan cycle to integrate transmission planning activities across the Western Interconnection. This process is designed to be adaptive, applying lessons learned to make adjustments and to guide future activities. As anticipated by the Protocol, TEPPC support of Regional planning during 2008 included an open request window and the incorporation of requested studies in the 2008 Study Plan and support of compliance filings made during 2008.[106]

TEPPC's 2008 activities produced significant study results that provide a solid basis for expanded study efforts in 2009 and beyond. Assistance came from the electric utility community, regulatory organizations, public interest groups, and vendors who collectively supplied data, improved models, and developed policies for economic planning of the Western Interconnection's transmission system.

TEPPC was established to address economic planning of the transmission system through the examination of congestion in the transmission system. TEPPC's primary tools for the congestion assessment are screening studies in two forms: historical data evaluations and long-term production cost simulations. In response to the Regional planning requirements of FERC's Order No. 890, TEPPC and the subregional planning groups have formalized these analytical activities into the Synchronized Study Plan process.

[105] www.wecc.biz/documents/library/TEPPC/2009/Part_1_Final_2008_Annual_Report.pdf

[106] Compliance filing support included working with the Northern Tier Transmission Group (NTTG) to develop a Regional planning road map that provides an integrated view of planning within the Western Interconnection. This road map will be further developed as a standalone document during 2009.

The Synchronized Study Plan, as described in the TEPPC Protocol, is designed to identify opportunities for improving economic performance of the transmission system. The delivery of new remotely located resources had long been a prime motivator of transmission expansion. However, adding transmission capacity also facilitates energy trading to produce a better overall dispatch of available resources across the system. In practice, the economic justification for new transmission is usually a combination of interconnecting new resources and energy trade opportunities.

As TEPPC activities reveal transmission needs and as projects are developed by the industry to meet those needs, projects naturally move from the realm of economic planning to reliability planning activities that fall under WECC's Planning Coordination Committee. TEPPC provides the economic intelligence needed by project developers — whether they are developers of demand-side services, builders of new resources, or developers of new transmission — to identify attractive investment opportunities for investors and customers, and to develop a business plan. TEPPC's activities are thus preparatory to more detailed technical reviews that are needed to seek regulatory permits and approvals, and to construct, install, and operate equipment or facilities.

The TEPPC 2009 study plan — developed in conjunction with Western industry, state regulators, and other stakeholders — is in the final stages of adoption at the time of this report and provides for additional studies of heavy renewables penetrations with more specific input from Western Load Serving Entities (LSE) and regulators. It also provides for longer-term (20-year, rather than ten-year) studies and an examination of the potential for constructing a higher-voltage overlay grid in the Western Interconnection as an additional support mechanism for higher renewables penetration.[107]

<u>Operating and Adequacy Issues</u>

High penetrations of variable renewable generation raise significant operating issues, which are becoming more widely understood through a number of WECC forums and Western study efforts, as well as NERC efforts such as the IVGTF.

WECC is concerned about the operation impacts of increasing levels of variable generation over the next 10 years. Concerns are centered on assuring that the Western Interconnection has the ability to operate efficiently and reliability. These concerns are categorized into three situations: high-load/high-variable generation, low-load/low-variable generation, and low-load/high-variable generation. Each of these situations imparts a different set of operating concerns, reliability risks, and possible solutions.

The high-load/high-variable generation poses the greatest risk to reliability from a resource adequacy perspective. In this case, the risk is a drop off of variable generation when it is needed most. To mitigate this risk, operating reserves are secured by BAs. The increase in variable generation would cause an increase in the level of reserves that must be carried.

[107] A draft of the TEPPC 2009 Synchronized Study Program is posted on the WECC Web site at www.wecc.biz/documents/meetings/board/TEPPC/2009/June/2009_TEPPC-Study-Program_V3-2(For%20Approval).doc

Low-load/low-variable generation poses the risk that variable generation would increase in the absence of other generation that can ramp down. This situation happens during off-peak periods and is worsened when it (frequently) coincides with periods of high hydro generation, which limits the flexibility of the hydro generators. Although there is not a significant resource adequacy risk, there are significant impacts to system operations and to what generation must be on-line. The increase in variable generation would impact what generation must be made available during this time, such as making combustion turbines run during off-peak to provide the necessary ramping capacity. In addition, the curtailment of the variable generation during these times would likely increase.

The low-load/high-variable generation poses the risk that variable generation would drop off during off-peak when much of the flexible generation is off-line. This is the least risk to reliability and operations since there are often other generation resources available to ramp up. However, with an increase in the level of variable generation, situations may arise where the level of variable and must-run generation exceeds load. As with the previous case, this situation often coincides with periods of high hydro generation.

WECC expects that a number of additional standards, guidelines, and rules would emerge from studies of the increase in variable generation and its impact on operations and reliability. Specifically, these would directly address the need to better forecast and control the fleet of variable generators in the Western Interconnection. In addition, changes to business practices and technologies that would enable higher levels of variable generation are anticipated. These include sub-hourly scheduling of energy and transmission, increased dynamic scheduling capability, and the expansion of ancillary service markets.

Currently, some entities in the Western Interconnection are making changes to their Large Generator Interconnection Agreements to address the controllability of large wind generating stations. These include provisions that range from forecasting requirements to enabling the BA to directly control output of the generator.[108]

A large number of variable generation (mostly wind) integration studies have been performed by entities in the Western Interconnection. Although the focus and intent of the studies are not identical, the primary objective is the same — quantify the impact of variable generation on operations and costs.

To facilitate a greater understanding and address of the effects of variable generation, WECC's Joint Guidance Committee created the Variable Generation Subcommittee (VGS) in October 2008. The subcommittee is made up of a broad set of stakeholders in the Western Interconnection. The purpose of the VGS is to provide a holistic perspective of the issues and opportunities related to the presence of variable generation in the Western Interconnection. It also serves to add value for WECC members by facilitating the development and implementation of solutions and by assuring reliability in the Western Interconnection. These challenges are being met through the compilation of information and member issues, coordination of issue analysis, and dissemination of information. As a recently formed subcommittee, the VGS is

[108] http://www.bpa.gov/corporate/WindPower/WIT.cfm, http://www.caiso.com/docs/2003/01/29/2003012914230517586.html

maturing. It is anticipated that the VGS would serve as the central point of facilitation for study of renewable issues in the Western Interconnection.
In addition to study activity in the Western Interconnection, there have been a number of pilot programs and operational changes to facilitate the integration of variable generation. These include balancing cooperation agreements between BAs, ancillary service agreements, and changes to transmission tariffs. Two examples of these are described below.

The ACE Diversity Interchange (ADI) is an example of BA cooperation to reduce the impacts of variable generation. It provides a mechanism for BAs to share their variability, which reduces the level of generation changes required by each entity. There are currently 16 BAs in the Western Interconnection participating in this activity. For the entities involved, participation has been shown to reduce balancing costs and improve NERC Control Performance Standard (CPS2) scores.

The Joint Initiative is a voluntary joint project sponsored by ColumbiaGrid, Northern Tier Transmission Group, and WestConnect. Collectively, these three Regional planning groups cover most of the two non-ISO areas of the Western Interconnection. In addition, the project has many participants among WECC member utilities, merchants, and stakeholders. The goal of the Joint Initiative is to tap into the existing flexibility that exists within the Western Interconnection. The Joint Initiative is recommending changes to Transmission Service Provider business practices to:

- Facilitate within-hour transmission purchase and scheduling.
- Develop tools to facilitate within-hour bilateral transactions.
- Develop a dynamic scheduling system consisting of standard protocols and communication infrastructure that would allow access to resources across multiple BA's, subject only to transmission constraints.

Operational issues vary significantly depending on the size of the BA, the mix of generation, penetration of wind, geographic dispersion of wind, market structure, and performance of wind plants. There are many and varied methods to mitigate the reliability and operational impacts of variable generation. However, these methods all focus on reducing the uncertainty of variable generation and accessing flexibility in the existing generation. This can be accomplished through:

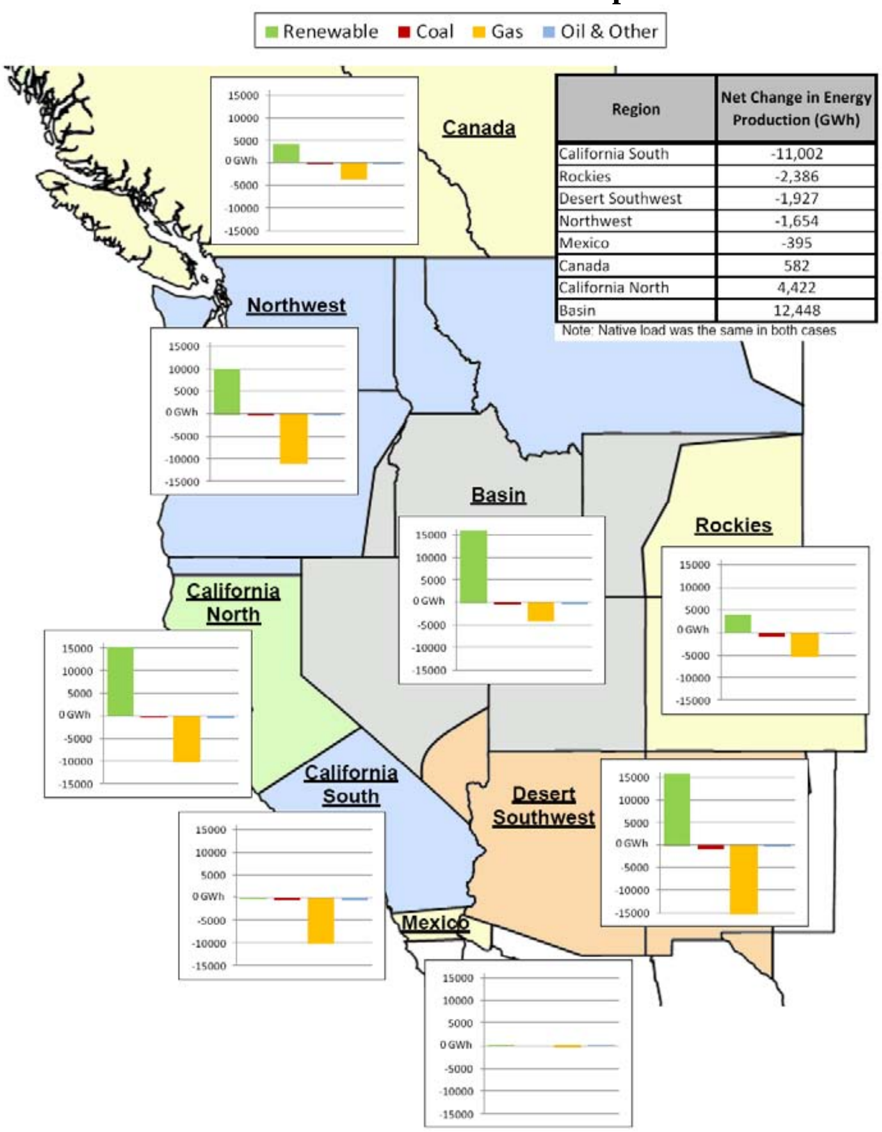
- Larger balancing areas (actual or virtual)
- Better wind forecasting
- Geographically dispersing wind generation over a larger area
- Increasing the amount of flexible generation (ramping capability)
- Ability to access flexible generation, including bi-lateral agreements between utilities or markets
- Rules and technology that allow for operational flexibility in near real-time through dynamic scheduling, intra-hour re-dispatch, and ancillary service markets

At high levels of variable generation — specifically wind — it is possible that ramp controls or generation caps may be necessary. The extent to which ramp or other operational limits are necessary would depend in large part on the other mitigation methods detailed above, transmission system additions, and the future technologies that enable more flexibility in the load.

<u>Fuel Use Impacts</u>

Figure 3 below shows the fuel use changes between the base case, which had approximately 8.8 percent renewables penetration and the 15 percent *Scenario Case*. As might be expected, the major change in fuel usage with the inclusion of large amounts of generation with low-to-zero variable cost is a decrease in gas usage. Gas generation is generally on the margin in the Western Interconnection.

**Figure WECC-3**
**FUEL USE CHANGES FROM RPS CASE TO 15 percent *SCENARIO CASE***




| Region | Net Change in Energy Production (GWh) |
|---|---|
| California South | -11,002 |
| Rockies | -2,386 |
| Desert Southwest | -1,927 |
| Northwest | -1,654 |
| Mexico | -395 |
| Canada | 582 |
| California North | 4,422 |
| Basin | 12,448 |

## Overview

The *Scenario Case* was constructed to examine the impacts of 15 percent renewables penetration in the Western Interconnection in 2017. Because of the limitations on the specific analysis and study construction, some of the impacts are not apparent from the study itself, but are known from other studies and activities that are being undertaken by WECC and other parties in the Western Interconnection.

The basic scenario study builds off two studies that were done by TEPPC:[109] a base case study that was done to examine the transmission planning impacts of meeting existing statutory RPS in the Western Interconnection (which yielded a renewables penetration of 8.8 percent) and the scenario study that increased the renewables penetration to 15 percent.

Because the two studies were designed to meet loads, there are no direct reliability impacts demonstrated by the studies. There are, however, operational impacts of high levels of variable generation that make up the bulk of the renewables in the study, and are known from other studies. These are described later in the report, along with the work being done by WECC and others in the Western Interconnection to address them, and prevent them from becoming reliability problems.

The following assumptions were used to develop the 2017 study data for the 2008 TEPPC Study plan.

[109] http://www.wecc.biz/documents/library/TEPPC/2009/CoverLetter_Exec_Summary_Final_V4_a.pdf

| Data Grouping | Key Assumptions |
|---|---|
| **Load Forecast** | • Source of the Data<br>  ▪ The 2006 L&R load forecast (data for the 2007 LTRA) is used for all areas except California and the Northwest which used modified forecasts.<br>• The load forecast for each bubble in the TEPPC topology is distributed to the bus level using the WECC power flow case.<br>• California loads and mapping to buses are adjusted to capture the unique characteristics of pumping plants in California.<br>• Transmission losses are included in the load forecasts. Currently, WECC does not have information to separate loss amounts.<br>• Existing and some forecasted demand side management (DSM) and Energy Efficiency programs are embedded in the load forecast. |
| **Network Representation and Topology** | • The criteria for including line additions in the 2017 Data Test Case was to initially include only transmission needed to for reliability or to integrate generation. This criterion was adopted to better highlight transmission needs in study results.<br>• Based upon comments submitted from the review of the Data Test Case, the following revisions were made:<br>  o The Palo Verde – Devers #2 500 kV line was turned off (but left in the data).<br>  o The Tehachapi Wind transmission was added.<br>  o Transmission was added from IID to the west (Sunrise project)<br>  o The Gateway project was submitted (connecting Wyoming generation to the west and south) but was not included in the case to better highlight the transmission need. The transmission would then be considered in Transmission Study Cases based on the 2017 Data Test Case.<br>• Topology: the topology was revised to approximately match the balancing authorities with exceptions to accommodate variations in load types and shapes as follows:<br>  o The CAISO is split into PG&E Bay, PG&E Valley, SCE, and SDGE bubbles.<br>  o Idaho/Wyoming is divided into six bubbles. |

| Data Grouping | Key Assumptions |
|---|---|
| **Generating Resources** | • The generating resources are assigned to bubbles and buses based on the previous SSG-WI data and the new power flow data. The category assignments are used to group the generators by similar operating characteristics, which are mainly derived from public sources.<br>Existing resources<br>• In accordance with the L&R definitions existing resources are resources assumed to be online by 12/31/2006. These resources were identified through the SSG-WI 2005, WECC L&R, WECC power flow case, EIA, and other data bases. The stakeholders were invited to review the list of resources and capacities, and their comments are included to the extent possible. Generating resource capacities are based on the power flow case or other sources. Thermal unit capacities are net of station service. Net to grid generation of cogeneration resources is not explicitly modeled except in Alberta. This is an area of improvement.<br>Incremental resources<br>• Incremental resource data collected for the L&R process (used to collect the LTRA data) was used to update the TEPPC data<br>• Incremental resources are resources expected to be placed in service between 2007 and the 2017 (inclusive).<br>• RPS resources<br>• The Studies Work Group determined the required RPS generation for each RPS State to meet the respective State requirement for 2017. Assumptions were made for discounts and conversions between energy and capacity. Where there were insufficient renewable resources in the existing and incremental generation, in either the RPS or *Scenario Cases*, generic RPS resources were added. Table 4 in section 8 details these resources by type and location. |

| Data Grouping | Key Assumptions |
|---|---|
| **Hydro Generation** | • The following sources of hydro data are used for the study:<br>o NW federal, Mid-C Nonfederal, and PacifiCorp: 2002 historical hourly hydro generation that is reasonably reflective of latest Biological Opinion.<br>o Other NW nonfederal: The hourly data for these units were calculated using a Proportional Load Following algorithm.<br>o California: The California hydro data is from the PI dataset which was aggregated to the river system and then disaggregated proportionally to the Pmax values of the units on that river system. The California hydro data is derived from historical 2003 data.<br>o WAPA: 2002 historical hourly hydro generation that is derived from the SCADA dataset.<br>o Canada: BC Hydro provided monthly hydro for adverse, average and above average hydro conditions grouped by their coastal, Peace River and Columbia River facilities. Data is shaped using year 2002 actual loads and hourly flows in and out of BC Hydro territory (BCH-US and BCH-Alberta paths), combined with treating the thermal generation as a block resource. Peak shaving algorithm is utilized for Piece River facility and the Proportional Load Following algorithm is used for the Costal and Columbia River facilities. |
| **Renewable Generation** | • Hourly wind shapes used to model all wind generating resources are supplied by National Renewable Energy Lab (NREL). Exception: CAISO provided wind shapes for its areas based on actual data. Wind is treated as a fixed input to the model.<br>• Geothermal plants are modeled as base load plants as confirmed by Clean and Diversified Energy Initiatives Geothermal Task Force. Data to model specific plants in CA is provided by CAISO.<br>• The incremental renewable resources from previous studies were replaced by data provided by the Studies Work Group.<br>• Solar production profiles are provided by NREL. |
| **DSM/Energy Efficiency** | • Existing and some forecasted DSM and Energy Efficiency programs are embedded in the load forecast. These amounts are not explicitly collected by WECC.<br>• The load data for California includes adjustments for anticipated efficiency programs. |

WECC conclusions are based primarily on the 15 percent *Scenario Case* and corresponding base case, rather than a comparison to the 2008 *Long-Term Reliability Assessment* case. Because these cases are constructed to meet study goals, they are not directly comparable to *Long-Term Reliability Assessment* cases since they consist, on the resource side, of a recounting of utility plans and expectations for independent generation development with varying levels of confidence.

For the study cases, WECC constructed a resource build-out based on RPS and 15 percent renewables penetrations, with additional resources submitted by utilities for the 2008 *Long-Term Reliability Assessment* and from generic resources needed to meet load-plus adequacy margins. WECC believes its approach would yield the most useful information for NERC about the consequences of high renewables penetrations in the Western Interconnection.

### Demand

The loads for the scenario, including the weather and economic assumptions, are based on the loads submitted for the 2007 *Long-Term Reliability Assessment*. This data was used since the 2008 *Long-Term Reliability Assessment* load data was not available at the time the TEPPC study process commenced. WECC does not believe that the key findings of the study were compromised by this decision. The peak loads are based on normal weather conditions with a 50 percent exceedence probability. The economic assumptions built into the load forecast were based on submittals by the utilities. WECC does not collect these economic assumptions nor does WECC create independent forecasts of economic conditions or loads.

The base case and the *Scenario Case* were based on the 2007 *Long-Term Reliability Assessment* loads. The difference between the scenario forecast and the 2009 *Long-Term Reliability Assessment* forecast for total WECC loads in 2017 is 7,580 MW. The primary difference between these two is the effect of the current recession on expectations for 2017 loads. Additionally, the demand reported in the 2009 *Long-Term Reliability Assessment* is a non-coincidental peak demand whereas the demand reported in the scenario is coincidental demand.

The WECC scenario used only renewable generation to meet the scenario target, and did not rely on the various demand management programs that are allowed by the scenario definition. In general, however, WECC would not expect any of these demand side programs to be adversely impacted due to high renewables penetration comparable to the penetrations in the *Scenario Case*. On the contrary, some of these programs — such as interruptible demand and direct control load management — offer significant benefits to utilities faced with the balancing and regulation problems posed by large amounts of variable generation (a prominent subset of renewable generation) in their BA areas. More details on demand management programs can be found in the NERC Special Report: *Accommodating High Level of Variable Generation*.[110]

### Generation

A vital metric used by NERC in its reliability assessment compares resources and projected peak internal demand. To increase the visibility and transparency of supply-side resource options being considered by Regions and subregions for this scenario assessment, NERC requires additional information regarding projected resources along with a comparison between the *Reference Case* and the scenario submittals.

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

Table 1 below shows the requested categories. Note that outside of the existing generation, the scenario consists largely of assumed generation to meet the scenario target; therefore, WECC does not believe it meets the criteria for either planned or proposed generation. However, for purposes of accounting for this information, WECC has categorized it all as Planned.

**Table WECC- 1 - Resource Mix**

| Category | Summer 2017 | | | | Winter 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2009 LTRA Resources (MW) | Resource Type (MW) | Scenario Resources (MW) | Resource Type (MW) | 2009 LTRA Resources (MW) | Resource Type (MW) | Scenario Resources (MW) | Resource Type (MW) |
| Region: WECC Wide | | | | | | | | |
| Existing Certain | 190,796 | | 194,656 | | 189,436 | | 178,686 | |
| Wind | | 951 | | 1,140 | | 778 | | 2,273 |
| Solar | | 396 | | 569 | | 370 | | 0 |
| Hydro | | 61,204 | | 25,869 | | 58,079 | | 21,984 |
| Biomass | | 1,340 | | 758 | | 1,339 | | 746 |
| Existing Uncertain | 15,174 | | 5,018 | | 19,390 | | 18,667 | |
| Wind | | 4,578 | | 3,814 | | 5,763 | | 2,681 |
| Solar | | 111 | | 1 | | 119 | | 543 |
| Hydro | | 7,933 | | 0 | | 9,355 | | 0 |
| Biomass | | 256 | | 33 | | 256 | | 45 |
| Inoperable | | 2,292 | | 1,170 | | 3,845 | | 15,398 |
| Planned | 12,940 | | 45,388 | | 11,095 | | 46,253 | |
| Wind Available | | 549 | | 3,537 | | 297 | | 7,754 |
| Wind Unavailable | | 2,884 | | 12,984 | | 1,763 | | 8,768 |
| Solar Available | | 284 | | 5,855 | | 0 | | 0 |
| Solar Unavailable | | 4 | | 454 | | 280 | | 6,211 |
| Hydro Available | | 1,736 | | 0 | | 1,422 | | 0 |
| Hydro Unavailable | | -103 | | 0 | | -103 | | 0 |
| Biomass Available | | 187 | | 755 | | 167 | | 610 |
| Biomass Unavailable | | 11 | | 42 | | 11 | | 71 |
| Proposed | 14,753 | | 0 | | 13,444 | | 0 | |
| Wind Available | | 440 | | 0 | | 392 | | 0 |
| Wind Unavailable | | 7,502 | | 0 | | 7,518 | | 0 |
| Solar Available | | 9 | | 0 | | 9 | | 0 |
| Solar Unavailable | | 0 | | 0 | | 0 | | 0 |
| Hydro Available | | 640 | | 0 | | 541 | | 0 |
| Hydro Unavailable | | 0 | | 0 | | 0 | | 0 |
| Biomass Available | | 166 | | 0 | | 161 | | 0 |
| Biomass Unavailable | | 0 | | 0 | | 0 | | 0 |

Some resources were added to the generation mix constructed by TEPPC in order to meet the reserve requirement of the TEPPC scenario. Proposed natural gas generating units were added to the Regions if additional resources were needed to meet the reserve margin of this case. If additional resources beyond the proposed units were needed, generic natural gas resources were added to meet the reserve requirement.

WECC studied the scenario for only one year, 2017, and both seasonal peaks are shown in the answers to the questions above.

WECC characterized all the resources beyond existing as planned. Resources were added to the existing system, starting with what WECC's *2008 Power Supply Assessment, Attachment 8: Generation Additions/Retirement*, characterized as follows:

- Class 1: under active construction with an expected in-service date prior to January 2012
- Class 2: all regulatory approvals, with a signed interconnection agreement, with an expected in-service date prior to January 2014
- Class 3: (gas-fired components): undergoing regulatory review and at least a facility study completed, with an interconnection agreement in active negotiation, with an expected in-service date prior to January 2014

TEPPC constructed the renewable generation mix to add to these resources for the RPS and 15 percent *Scenario Cases*. TEPPC used judgment to create a reasonable distribution of renewable resource types from those being considered by WECC members and a reasonable physical distribution of those resources across the Western Interconnection. More information on the mix of renewable resources and their locations can be found in the 2008 TEPPC Annual Report[111], and the TEPPC white paper on Renewable Energy Cases.[112]

Finally, TEPPC added sufficient load-center gas-fired generation to meet reserve margin targets. The addition of renewable resources to the 8.8 percent (RPS) case displaced non-renewable resources that had been needed to match resources with demand, creating an excess of resources that contributed to the reserve target.

Due to the nature of the scenario construction process, there is little comparability with the resources in the 2009 *Long-Term Reliability Assessment*, which represents specific utility plans and their expectations of independent developer behavior, modified by their application of confidence factors.

### Purchases and Sales on Peak

WECC does not gather data about contractual sales or purchases, which are in any case largely irrelevant to the adequacy analysis WECC performs. In WECC's analysis, resources are dispatched to meet loads subject to transmission constraints. WECC simulates the entire interconnection, so there is no load or resource that is outside the sphere of the analysis, aside from a minimal amount of transactions across interconnection boundaries with Midwest Reliability Organization (MRO) and Southwest Power Pool (SPP), which were not included in the analysis. This treatment of transfers removes any potential for double counting of resources. WECC does not monitor each load serving entity's supply status, but instead studies the supply situation of the interconnection as a whole. Because WECC is not reporting any external transactions and is only reporting data for the entire interconnection, there is no data to be reported in this section.

### Fuel

WECC answers this question through an hourly simulation rather than a simple comparison of peak loads and peak resources, so WECC compared the base case with the *Scenario Case*. This comparison showed the effect of the additional approximately 7 percent renewables penetration. The fuel supply effects are largely a reduction in gas use, on top of whatever reduction in gas use would come from meeting the RPS requirements in the first place. It is unclear whether a 15 percent renewable case increases or decreases fuel supply vulnerability. From the vantage point of annual fuel use, reduced usage would tend to reduce pressure to develop new and replacement supplies or expand the natural gas transmission system. The intermittency of wind and central

[111] http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=172
[112] http://www.wecc.biz/documents/library/TEPPC/TEPPC-15-Renewable_Energy_Generation_Paper_9-12-08.pdf

solar, on the other hand, could combine with hydro variability to cause localized gas shortages should fossil power plants with slack generating capability be used to provide replacement energy reserves.

The effects would be largely on commercial contracts, minimum takes of gas, gas scheduling, gas storage capacity, and so forth; which would need to be examined further in the future, particularly to the extent that the increasing renewables penetration is made up of variable generation like wind (and to a lesser extent, solar).  As noted in the Introduction and Summary, the CEC has conducted two studies examining broad implications on natural gas for power generation under various high renewable scenarios for the Western Interconnection. Many questions regarding fuel vulnerability remain for further study.

Table 2 below shows the changes in fuel use between the 15 percent scenario and the RPS case.

| Table WECC-2: Comparison of Energy Results by Category | | | | |
|---|---|---|---|---|
| **Generation Results (MWh)** | | | | |
| **Category** | 8.8 percent (RPS) Renewables | 15 percent Renewables | Difference | Diff percent |
| Conventional Hydro | 247,488,545 | 247,488,544 | (1) | 0.0 percent |
| Pumped Storage | 1,377,489 | 750,985 | (626,503) | -45.5 percent |
| Steam – Coal | 288,608,846 | 285,814,830 | (2,796,815) | -1.0 percent |
| Steam – Other | 17,551,927 | 12,004,708 | (5,552,239) | -31.6 percent |
| Nuclear | 72,487,213 | 72,482,901 | (4,312) | 0.0 percent |
| Combined Cycle | 311,369,001 | 259,278,246 | (52,068,696) | -16.7 percent |
| Combustion Turbine | 19,177,905 | 15,182,948 | (4,002,519) | -20.8 percent |
| GTC | 13,779 | 6,926 | (6,256) | -49.7 percent |
| IC | 2,978 | 1,016 | (1,735) | -65.9 percent |
| Synthetic Crude Tar Sands | 3,348,501 | 3,060,507 | (288,929) | -8.6 percent |
| Biomass RPS | 6,473,885 | 10,389,102 | 3,914,260 | 60.5 percent |
| Geothermal | 22,221,153 | 51,027,441 | 28,806,289 | 129.6 percent |
| Small Hydro RPS | 2,372,443 | 2,372,442 | (1) | 0.0 percent |
| Solar | 8,175,985 | 24,545,047 | 16,369,061 | 200.2 percent |
| Wind | 54,039,205 | 70,391,909 | 16,352,705 | 30.3 percent |
| **Total** | **1,054,708,855** | **1,054,797,552** | **94,309** | **0.0 percent** |
| **Renewable Total** | **93,282,671** | **158,725,942** | **65,442,314** | **70.2 percent** |
| **Renewable Percent** | **8.8 percent** | **15.0 percent** | **0** | **70.1 percent** |

## Transmission

The WECC study of the 15 percent *Scenario Case* did not develop a full build-out of the transmission system additions that would be necessary for the generation that was added. Rather, it identified the principle paths that would need to be expanded to accommodate that added generation. The further actual development of the transmission system to accommodate whatever added generation would actually be required by individual utilities in the Western Interconnection would be a function of the actual pattern of renewable generation development, which could be similar to or different from the locations simulated in the *Scenario Case*.

A list of the constrained transmission paths as produced through the scenario studies, and a description of the constrained paths, are detailed in Charts 1 and 2 below.
The transmission expansion was not studied in the level of detail to allow a complete characterization of the required transmission build out.

**Table WECC-1: Most Often Constrained Transmission Paths**

| Path Index | Path Name | Max Neg Limit | Max Pos Limit | 75% Limit | 90% Limit | 99% Limit | Shadow Price (k$) | Rank 75% Limit | Rank 90% Limit | Rank 99% Limit |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | IPP DC LINE | -1400 | 1920 | 92.9% | 86.4% | 81.6% | | 3 | 1 | 1 |
| 2 | TABLE MOUNTAIN - VACA DIXON | -2145.9 | 2145.9 | 86.3% | 73.9% | 63.2% | -280.62 | 4 | 3 | 3 |
| 3 | FOUR CORNERS 345/500 KV | -840 | 840 | 80.3% | 66.8% | 55.7% | -214.44 | 7 | 4 | 4 |
| 4 | ALBERTA - BRITISH COLUMBIA | -720 | 700 | 60.0% | 51.5% | 46.6% | -43.51 | 13 | 5 | 5 |
| 5 | MONTANA - NORTHWEST | -1350 | 2200 | 68.0% | 48.8% | 34.8% | -85.47 | 9 | 6 | 6 |
| 6 | TOT 2C | -300 | 300 | 63.9% | 46.8% | 34.4% | -106.32 | 10 | 8 | 7 |
| 7 | PACIFIC DC INTERTIE (PDCI) | -2780 | 3100 | 33.6% | 28.5% | 20.5% | | 32 | 16 | 9 |
| 8 | WYOMING TO UTAH | not defined | 1700 | 81.6% | 43.0% | 18.8% | -21.68 | 6 | 11 | 10 |
| 9 | TOT 4A | -810 | 810 | 62.4% | 32.9% | 14.6% | -25.29 | 12 | 12 | 12 |
| 10 | MIDPOINT - SUMMER LAKE | -600 | 1500 | 58.2% | 29.0% | 12.0% | -30.33 | 15 | 13 | 14 |
| 11 | PV West | not defined | 3600 | 59.0% | 28.7% | 11.9% | -7.36 | 14 | 15 | 16 |
| 12 | Tot 2a 2b 2c Nomogram | -1600 | 1570 | 49.7% | 25.1% | 11.3% | -11.00 | 20 | 19 | 17 |
| 13 | BRIDGER WEST | not defined | 2200 | 45.4% | 20.6% | 9.3% | -16.42 | 22 | 20 | 18 |
| 14 | TOT 2A | -690 | 690 | 35.4% | 16.9% | 8.3% | -8.37 | 27 | 23 | 19 |
| 15 | NW to Canada East BC | -400 | 400 | 19.3% | 9.9% | 5.8% | -14.74 | 52 | 34 | 21 |
| 16 | TOT 2B1 | -600 | 560 | 26.1% | 12.9% | 4.9% | -3.67 | 46 | 26 | 23 |
| 17 | West of John Day | not defined | 2650 | 32.8% | 18.6% | 4.7% | -5.72 | 36 | 21 | 24 |
| 18 | TOT 3 | -1800 | 1800 | 34.5% | 10.3% | 3.5% | -5.96 | 31 | 33 | 26 |
| 19 | TOT 2B | -850 | 780 | 31.3% | 14.8% | 3.4% | -2.38 | 38 | 24 | 27 |
| 20 | LUGO - VICTORVILLE 500 KV LINE | -900 | 2400 | 35.0% | 11.1% | 3.1% | -3.40 | 28 | 31 | 28 |

**Notes to this table:**

- Paths are sorted based on "Rank 99% Limit"
- The following paths were omitted from the list because congestion on the path was due to a local resource issue: SDG&E Mexico (CFE), SANMATEO_30700 To MARTIN C_30695, NEWARK D_30630 To RAVENSWD_30703
- The following phase shifting transformers were omitted from the list: California Substation Phase Shifter, Nelway Phase Shifter
- The following paths were omitted from the list because they are covered as part of another path also on the list: Z9-HA-Red Butte PS (part of TOT 2C), BURNS_45029 To SUMMER L_41043 (part of MIDPOINT - SUMMER LAKE)
- INTERMOUNTAIN - MONA 345 KV was omitted from the list because congestion on this path is driven by loading of the IPP DC line

| Table WECC-2: Path Descriptions | |
|---|---|
| **Path Name** | **Path Description** |
| IPP DC Line | Line from Intermountain station in central Utah to Adelanto station in southern California |
| Table Mountain - Vaca Dixon | North of San Francisco area |
| Four Corners 345/500 kv | Northeastern Arizona |
| Alberta - British Columbia | Southern Alberta and southern British Columbia |
| Montana - Northwest | The lines between western Montana and the Northwest |
| TOT 2C | Southwestern Utah to southeast Nevada |
| Pacific DC Intertie | Line from Celilo station (Big Eddy area) in northern Oregon to the Sylmar station in southern California |
| Wyoming to Utah | Border between Wyoming and Utah |
| TOT 4A | Southwest Wyoming |
| Midpoint - Summer Lake | Southwest Idaho and eastern Oregon |
| PV West | Western Arizona |
| TOT 2A 2B 2C Nomogram | Roughly the entire border of southern Utah |
| Bridger West | Border between southeast Idaho and southwest Wyoming |
| TOT 2A | Extreme southwest Colorado |
| NW to Canada East BC | Washington and southern British Columbia |
| TOT 2B1 | Southern Utah to N. Arizona/W. New Mexico |
| West of John Day | West of John Day in northern Oregon |
| TOT 3 | Border between northeast Colorado and southwest Wyoming |
| TOT 2B | Southern Utah to N. Arizona |
| Lugo - Victorville 500kv Line | Transmission line from LADWP's Victorville substation to SCE's Lugo substation |

## Operational Issues

The operating issues that vary from the *Long-Term Reliability Assessment Reference Case* are driven by the increase in variable generation (wind and solar). There are no material operational impacts from an increase in other renewable generation (geothermal and biomass) in the *Scenario Case*.

WECC is concerned about the operation impacts of increasing levels of variable generation over the next 10 years. These concerns are centered on assuring that the Western Interconnection has the ability to operate efficiently and reliability and are categorized into three situations: high-load/high-variable generation, low-load/low-variable generation, and low-load/high-variable generation. Each of these situations imparts a different set of operating concerns, reliability risks, and possible solutions.

The high-load/high-variable generation poses the greatest risk to reliability from a resource adequacy perspective. In this case, the risk is a drop off of variable generation when it is needed most. To mitigate this risk, operating reserves are secured by BAs. The increase in variable generation would cause an increase in the level of reserves that must be carried.

Low-load/low-variable generation poses the risk that variable generation would increase in the absence of other generation that can ramp down. This situation happens during off-peak periods and is worsened when it (frequently) coincides with periods of high hydro generation, which limits the flexibility of the hydro generators. Although there is not a significant resource adequacy risk, there are significant impacts to system operations and to what generation must be on-line. The increase in variable generation would impact what generation must be made available during this time, such as making combustion turbines run during off-peak to provide the necessary ramping capacity. In addition, the curtailment of the variable generation during these times would likely increase.

The low-load/high-variable generation poses the risk that variable generation would drop off during off-peak when much of the flexible generation is off-line. This is the least risk to reliability and operations since there are often other generation resources available to ramp-up. However, with an increase in the level of variable generation, situations may arise where the level of variable and must-run generation exceeds load. As with the previous case, this situation often coincides with periods of high hydro generation.

WECC expects that a number of additional standards, guidelines, and rules would emerge from studies of the increase in variable generation and its impact on operations and reliability. Specifically, these would directly address the need to better forecast and control the fleet of variable generators in the Western Interconnection. In addition, changes to business practices and technologies that would enable higher levels of variable generation are anticipated. These include sub-hourly scheduling of energy and transmission, increased dynamic scheduling capability, and the expansion of ancillary service markets.

Currently, some entities in the Western Interconnection are making changes to their Large Generator Interconnection Agreements to address the controllability of large wind generating stations. These include provisions that range from forecasting requirements to enabling the BA to directly control output of the generator.[113]

**Renewable/Variable Generation Studies in WECC**
A large number of variable generation - mostly wind - integration studies have been performed by entities in the Western Interconnection. Although the focus and intent of the studies are not identical, the primary objective is the same — quantify the impact of variable generation on operations and costs. The table below outlines a subset of these studies.

To facilitate a greater understanding and address of the effects of variable generation, WECC's Joint Guidance Committee created the Variable Generation Subcommittee (VGS) in October 2008. The subcommittee is made up of a broad set of stakeholders in the Western Interconnection. The purpose of the VGS is to provide a holistic perspective of the issues and opportunities related to the presence of variable generation in the Western Interconnection. It also serves to add value for WECC members by facilitating the development and implementation of solutions by and assuring reliability of the Western Interconnection. These challenges are being met through the compilation of information and member issues, coordination of issue analysis, and dissemination of information. As a recently formed subcommittee, the VGS is maturing. It is anticipated that the VGS would serve as the central point of facilitation for study of renewable issues in the Western Interconnection.

[113] http://www.bpa.gov/corporate/WindPower/WIT.cfm,
http://www.caiso.com/docs/2003/01/29/2003012914230517586.html

| Partial List of Current/Past Variable Generation Study Activities in the Western Interconnection |
|---|
| **AESO Wind Integration Impact Studies**<br>The purpose of these studies was to assess the impact of existing and additional levels of wind capacity on the safe and reliable operation of the Alberta Interconnected Electric System, and to assess the merits of mitigation measures to maintain acceptable system performance. |
| **Alberta Wind System Impact Study & Dispatch Simulation Model**<br>The AESO developed a dispatch simulation model to be used for analyzing and assessing the operational impacts of wind power and the effectiveness of new mitigating measures. |
| **AESO development of technical requirements for wind power facilities.** |
| **AESO Wind Power Forecasting Pilot Project**<br>The purpose of AESO's pilot project was to test various wind power forecasting methods and providers, and to identify the most effective methods/providers to forecast wind power in Alberta. |
| **Market & Operational Framework for Wind Integration in Alberta**<br>This framework will form the foundation for work required to further refine and define rules, tools and procedures needed to integrate as much wind power into the Alberta system as is feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market. |
| **BPA Simulation of Wind Generation in Resource Adequacy Assessments**<br>Study investigates the reliable capacity available from wind generation in the BPA BA, the correlation of wind generation and temperature, and creating long-term synthetic data records. |
| **2007 CAISO Study in Integration of Renewable Resources (IRRP)**<br>Purpose of the study is to identify integration issues and solutions for the integration of large amounts of renewable resources into the ISO Control Area. Particular focus on accommodating 20 percent and 33 percent RPS. |
| **2007 CEC Study – Intermittency Analysis Project**<br>The study examined several aspects of large scale development of intermittent renewable resources, principally in California, but also in related areas which might be exported specifically to California. |
| **Idaho Power Wind Integration Study**<br>The study identified operational impacts of integrating wind generation into Idaho Power's existing resource portfolio and outlined a basic approach for integrating the wind as studied. |
| **Joint Initiative**<br>Sponsored by ColumbiaGrid, NTTG, and WestConnect<br>The goal of the JI is to encourage and facilitate Western Interconnection parties to jointly develop and implement high-value cost-effective Regional products to assist with the integration of non-dispatchable resources. |
| **2007 NW Wind Integration Action Plan and 2009 Phase II Study**<br>Efforts address the challenge of how to best integrate wind energy into the Pacific Northwest's existing hydro-rich electricity system. |
| **WECC Modeling and Validation Work Group proposed standard for submitting generator models for WECC base cases.** |
| **CAISO Storage Pilot Program** |

| |
|---|
| Efforts to accommodate storage devices with limited storage capability in connection with FERC Order 890. |
| **PNNL study in conjunction with BPA and CAISO on Wide Area Energy Storage and Management System to balance intermittent resources.** The study assesses regulation sharing opportunities and assesses the effect of fast regulation resources. |
| **NREL/Oakridge study to quantify the benefit of combined BA operations on ramp requirements in systems with significant wind penetration.** |
| **NREL/WestConnect/GE study of large scale wind integration in WestConnect footprint and the impacts of combined BA operations.** |
| **NREL study to investigate the capacity and ramping impacts of wind energy on power systems**<br>The study identified opportunities for improving the efficiency of inter-BA wind transfers. |
| **NREL study on tariff design and its influence on the availability of ancillary services.** |
| **BPA use of software to modify variable generation output with over generation condition and reserve levels depleted and modifying tags when under generation condition exists and reserve levels depleted.** |
| **PG&E development of prototype tool to estimate required regulation, load following, and day-ahead commitment capacity, and integration costs for different levels of intermittent resources.** |

In addition to study activity in the Western Interconnection, there have been a number of pilot programs and operational changes to facilitate the integration of variable generation. These include balancing cooperation agreements between BAs, ancillary service agreements, and changes to transmission tariffs. Two examples of these are described below.

The ACE Diversity Interchange (ADI) is an example of BA cooperation to reduce the impacts of variable generation. It provides a mechanism for BAs to share their variability, which reduces the level of generation changes required by each entity. There are currently 16 BAs in the Western Interconnection participating in this activity. For the entities involved, participation has been shown to reduce balancing costs and improve NERC Control Performance Standard (CPS2) scores.[114]

The Joint Initiative is a voluntary joint project sponsored by ColumbiaGrid, Northern Tier Transmission Group, and WestConnect. Collectively, these three Regional planning groups cover most of the two non-ISO areas of the Western Interconnection. In addition, the project has many participants among WECC member utilities, merchants, and stakeholders. The goal of the Joint Initiative is to tap into the existing flexibility that exists within the Western Interconnection. The Joint Initiative is recommending changes to Transmission Service Provider business practices to:

- Facilitate within-hour transmission purchase and scheduling.
- Developing tools to facilitate within-hour bilateral transactions.

[114] http://www.columbiagrid.org/ace-diversity-overview.cfm

- Developing a dynamic scheduling system consisting of standard protocols and communication infrastructure that would allow access to resources across multiple Balancing Authorities, subject only to transmission constraints.[115]

**Potential Operational Issues Lessons-Learned**

Operational issues vary significantly depending on the size of the BA, the mix of generation, penetration of wind, geographic dispersion of wind, market structure, and performance of wind plants. There are many and varied methods to mitigate the reliability and operational impacts of variable generation. However, these methods all focus on reducing the uncertainty of variable generation and accessing flexibility in the existing generation. This can be accomplished through:

- Larger balancing areas (actual or virtual)
- Better wind forecasting
- Geographically dispersing wind generation over a larger area
- Increasing the amount of flexible generation (ramping capability, increased regulation requirements, decreasing minimum points for fossil power plants, increased need for fast start from cold conditions for fossil power plants)
- Ability to access flexible generation, including bi-lateral agreements between utilities or markets
- Rules and technology that allow for operational flexibility in near real-time through dynamic scheduling, intra-hour re-dispatch, and ancillary service markets

**Operational Limits and Conditions**

At high levels of variable generation — specifically wind — it is possible that ramp controls or generation caps may be necessary. The extent to which ramp or other operational limits are necessary would depend in large part on the other mitigation methods detailed above, transmission system additions, and the future technologies that enable more flexibility in the load.

## Reliability Assessment Analysis

WECC constructed this scenario to meet the required study goals and it is not directly comparable to the *Long-Term Reliability Assessment* case. Renewable resources were distributed across WECC based on areas of high resource potential, as consistent with existing Western RPS requirements. However, no attempt was made to simulate the assignment of any particular resource or set of resources to any particular LSE or Region. Using a different set of assumptions the results could be, and should be, vastly different.

Given that the *Long-Term Reliability Assessment* is based on utility-submitted resources and the scenario is designed to meet resource adequacy margin targets, the meaning and value of a comparison of this type is not clear. The differences are entirely a function of the study process and not of any inherent characteristics of the resources involved or of utility plans.

WECC does not currently do LOLE, EUE, etc., studies. It assesses resource adequacy against target reserve margins.

[115] http://www.columbiagrid.org/ji-nttg-wc-overview.cfm

WECC did not do a *Scenario Case* for any year except 2017. The 2017 study is designed to meet the required target reserve margin.

Table 4 below shows the type of renewable resources, and the amount of capacity that was added to meet the 15 percent renewable energy requirement.

| Table WECC-4: Resource Type and Location | | | | |
|---|---|---|---|---|
| Location | Biomass Resources (MW) | Geothermal Resources (MW) | Solar Resources (MW) | Wind Resources (MW) |
| Canada | 48 | 0 | 0 | 1,803 |
| Northwest | 148 | 430 | 0 | 5,247 |
| Southwest | 0 | 0 | 3,034 | 2,930 |
| Basin | 73 | 2,140 | 1,358 | 551 |
| Rockies | 76 | 0 | 239 | 3,981 |
| Cal./Mex. | 574 | 2,221 | 1,810 | 3,847 |
| Total | 918 | 4,792 | 6,441 | 18,359 |

This question is not applicable, given that resources were added to meet the described scenario requirement. It is meaningless to compare the results from the *Long-Term Reliability Assessment* and the scenario. The *Long-Term Reliability Assessment* and the scenario look at resources chosen by different processes and designed for different purposes.

The target reserve margin used by WECC is designed to cover a 1-in-10 weather-driven load event defined by balancing area and aggregated by Region in WECC.

For the scenario study, a meso-scale model was used to create energy curves that represent the expected energy available from wind and solar resources. For wind, the three-year (2004-2006) data set is comprised of over 30,000 2km by 2km squares, each with a time resolution of 10 minutes and 1 hour. The solar data set is over the same three-year period, but at a resolution of 10 km and 15 minutes and 1 hour. The primary strength of the meso-scale model is its use of time synchronized data. This data would show the effects of geographical diversity on net generation within a Region as well as within WECC as a whole.[116]

Energy-only and transmission-limited resources are not included in the scenario or the 2008 *Long-Term Reliability Assessment* studies.

Known unit retirements are recognized in the resources counted in both the *Long-Term Reliability Assessment* and the renewable scenario. Neither the *Long-Term Reliability Assessment* nor the scenario explicitly examines the effect of currently-unknown resource retirements.

[116] Additional detail is available in: http://www.wecc.biz/documents/library/TEPPC/TEPPC-15-Renewable_Energy_Generation_Paper_9-12-08.pdf

WECC interprets this question to be about local deliverability, rather than about additions to the bulk transmission system addressed in Section 6. Generally, the transmission analysis done for the LRTA cases is not detailed enough to address deliverability into local load centers from the high-voltage grid. In its resource adequacy analysis, WECC considers such issues the responsibility of the local transmission providers. However, WECC believes that this simplified method of analysis captures major elements of deliverability tied to the major transmission paths within WECC. The question of projected ATC and contractual transmission rights involves data that WECC does not collect and believes is irrelevant to interconnection-wide reliability analyses.

As shown in the *Transmission* section, major path upgrades would be required to deliver the new renewable generation hypothesized in the scenario to load centers. If the generation were developed as in the scenario and if that transmission were not constructed, the capacity represented by the renewables that would not be deliverable would have to be made up by local generation or additional demand-side measures.

Generally, the transmission analysis done for the LRTA cases is not detailed enough to address deliverability into local load centers from the high-voltage grid. In its resource adequacy analysis, WECC considers such issues the responsibility of the local transmission providers. The scenario analysis also is not detailed enough to address distribution deliverability questions.

The need for additional operating reserves for balancing within-hour variable generation (such as wind), to ensure meeting the BAL standard, is already becoming a prominent issue for BAs with large amounts of variable generation to manage, such as BPA. This is doubly an issue when substantial portions of the variable generation are intended to be delivered to loads in other BAs (again, BPA is a prime example). Changes in market structure and mechanisms are being studied in the Western Interconnection as one means of dealing with this kind of within-hour balancing problem.

# About This Report

**Background**

Each year,[117] NERC's staff and its technical committees prepare a ten-year *Long-Term Reliability Assessment* (LTRA). This preparation includes data concentrated on Summer and Winter peak internal demand and associated demand and supply capacity, along with separately written Regional self-assessments. These assessments form the basis for the *NERC Reference Case*, for which detailed analysis and discussion follows. The *Reference Case* generally is based on the assumption that policy/regulations will be constant throughout the studied timeframe and a variety of economic growth, weather patterns and system equipment behaves at expected, usually based on historic performance trends.

Scenario analysis can indicate the relative sensitivity of the *Reference Case* to changes in pre-specified conditions and may provide some insight into risks to Regional reliability. Based on feedback from FERC and industry, a deeper understanding is desired regarding the potential reliability implications of a focused spectrum of *Reference Case* sensitivities. Development of a small set of scenarios for comparison to the *Reference Case* is an extremely valuable way to better understand the robustness of the *Reference Case* and to study potential impacts of scenarios on reliability.

For the 2008 *Long-Term Reliability Assessment* cycle, NERC began development of plans to address scenarios identified in the 2007 *Long-Term Reliability Assessment*. The plans were developed to address the scenarios which were studied during 2008, and the results published in this report. In the summer of 2008, the Planning Committee was requested to prioritize emerging issues for possible scenario assessment plans developed in 2009 for study in 2010, using a simplified risk analysis approach. This process will continue in this fashion so that the *Long-Term Reliability Assessment* will include not only the *Reference Case*, but also specific scenario analysis if a scenario is chosen by the PC. Figure 8 outlines the enhanced process.

To implement Emerging Issues and Scenario analysis into the reliability assessment, the NERC Planning Committee adopted a process in December 2007 that includes identification of emerging issues, based on input from its subcommittees, for possible Regional and NERC-wide evaluation. Transmission and resource (including internal demand) emerging issues will be proposed for Planning Committee consideration, and if an issue is selected for a scenario assessment, this scenario would be provided for Regional entity reliability assessment as part of the data requests. Based on input from the industry, analysis could include both adequacy and security issues which are affected by issues such as:

- Substantial Non-dispatchable Resources Penetration
- High level of Demand Response Penetration[118]
- Weather uncertainty evaluation
- Gas deliverability and supply
- Capacity planning indicators that are separate from energy planning indicators

[117] From the Reliability Assessment Guidebook[117], Version 1.2, 3/18/09:
[118] This activity has been taken up by the (Demand-Side Management Task Force), under the direction of the Resource Issues Subcommittee.

- Nuclear scenarios, e.g. what if large nuclear units do not come on-line?
- Transformation from summer to winter peaking in some Regions

PC selected scenarios should be summarized by the Regional Entities as part of their submitted Regional assessments. Full reports could be provided to NERC[119] as supporting documentation for Regional and long-term reliability assessments when they become available. Figure 8 shows the recommended flowchart for this process (as approved by the PC in December 2007).

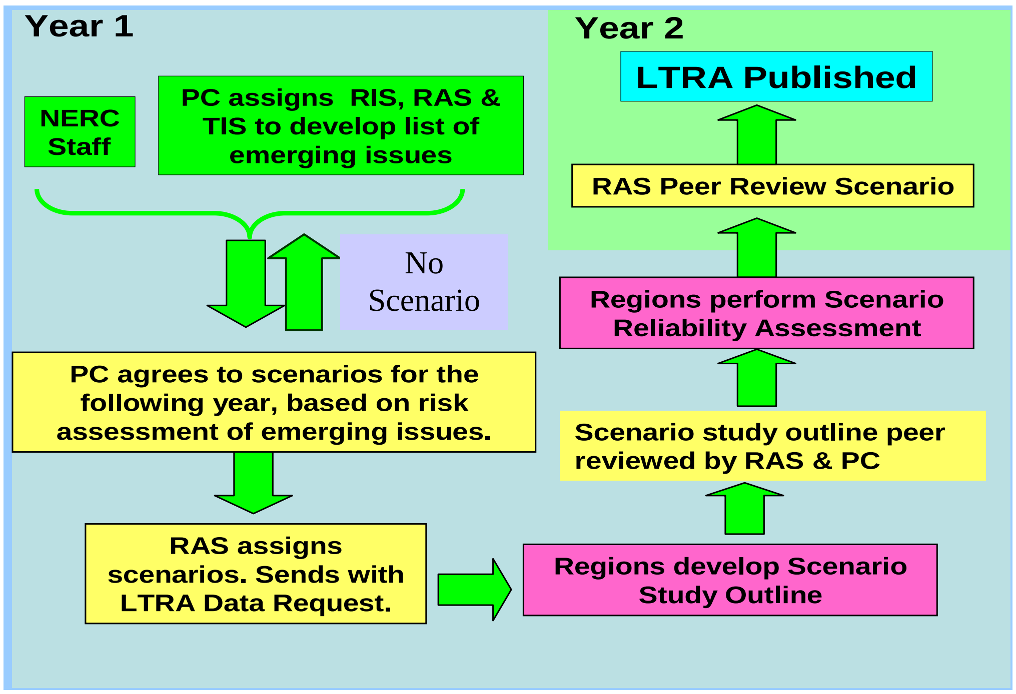



**Figure 8: 2008 Emerging Issues and Scenario Analysis**

### Report Preparation

From the *2008 Long-Term Reliability Assessment*[120]:

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

119 Confidential Information will be handled by NERC staff, following Section 1500 of NERC's Rules 7 Procedures ( http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20081219.pdf )
120 http://www.nerc.com/files/LTRA2008v1_2.pdf

# Joint Coordinated System Plan

### Joint Coordinated Study Plan (JCSP) Used by MRO, RFC, and SPP

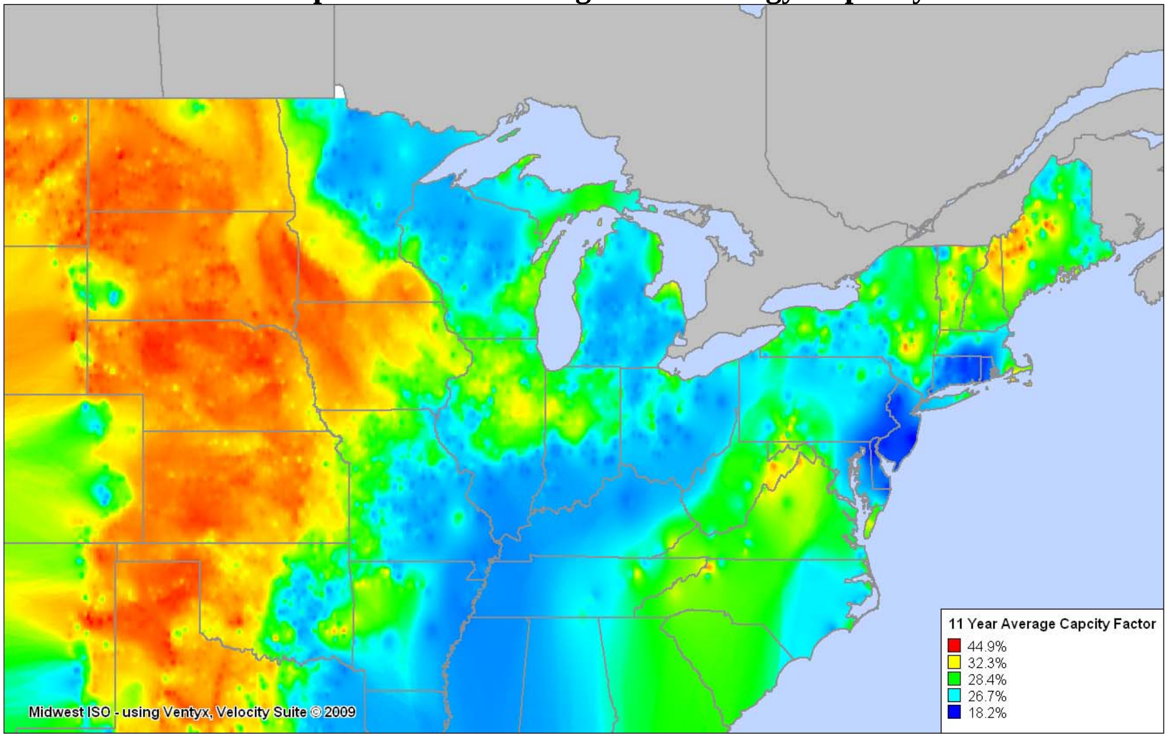
Since the study parameters of this scenario assessment closely matched an existing major study effort at the time, three of the Regional Entities (MRO, RFC, and SPP) within the Eastern Interconnection relied upon the results of the recently completed 2008 Joint Coordinated Study Plan (JCSP)[121] for their scenario analysis assessment. The JCSP effort covered most of the Eastern Interconnection (and the entire MRO, RFC, and SPP footprints) and studied two cases, a Reference *Scenario Case* and a 20 percent Wind Energy *Scenario Case* for the 2024 study year. The Reference *Scenario Case* assumes that the existing laws and policies governing generation resource choices remain in place and was premised on the assumption that incremental wind development would address existing Renewable Portfolio Standards (RPS) requirements as of January 1, 2008, which translated into an average 5 percent wind generation development across the United States portion of the Eastern Interconnection. The Reference Scenario assumes each state will build as much new on-shore wind generation as its total RPS requires and will be built as close as possible to the Regional load. The 20 percent Wind Energy Scenario assumes that the entire Eastern Interconnection will meet 20 percent of its electrical energy needs using wind generation by 2024. The JCSP analysis offers one coordinated Regional generation and transmission system conceptual scenario to integrate a large amount of new wind generation that could accommodate 20 percent of the total electrical energy needs in 2024.

The JCSP study also included sufficient resources to maintain resource adequacy throughout its study, with a 15 percent reserve margin assumed for both the reference and wind *Scenario Cases*.

The map below shows details of the DOE mesoscale 11-year energy capacity factors for much of the Eastern Interconnection. The majority of high quality wind is located in the Great Plains Region. These high capacity factors make for an increased potential that wind generating units beyond what is required to meet local RPS mandates or goals will be sited within the red and orange areas of the map (i.e. MRO and SPP footprints). In the study, large amounts of wind generation are conceptually sited in the western part of the Eastern Interconnection (specifically in the MRO and SPP footprints) where there are superior inland wind resources to more economically serve load on the east coast of the United States

[121] See www.jcspstudy.org

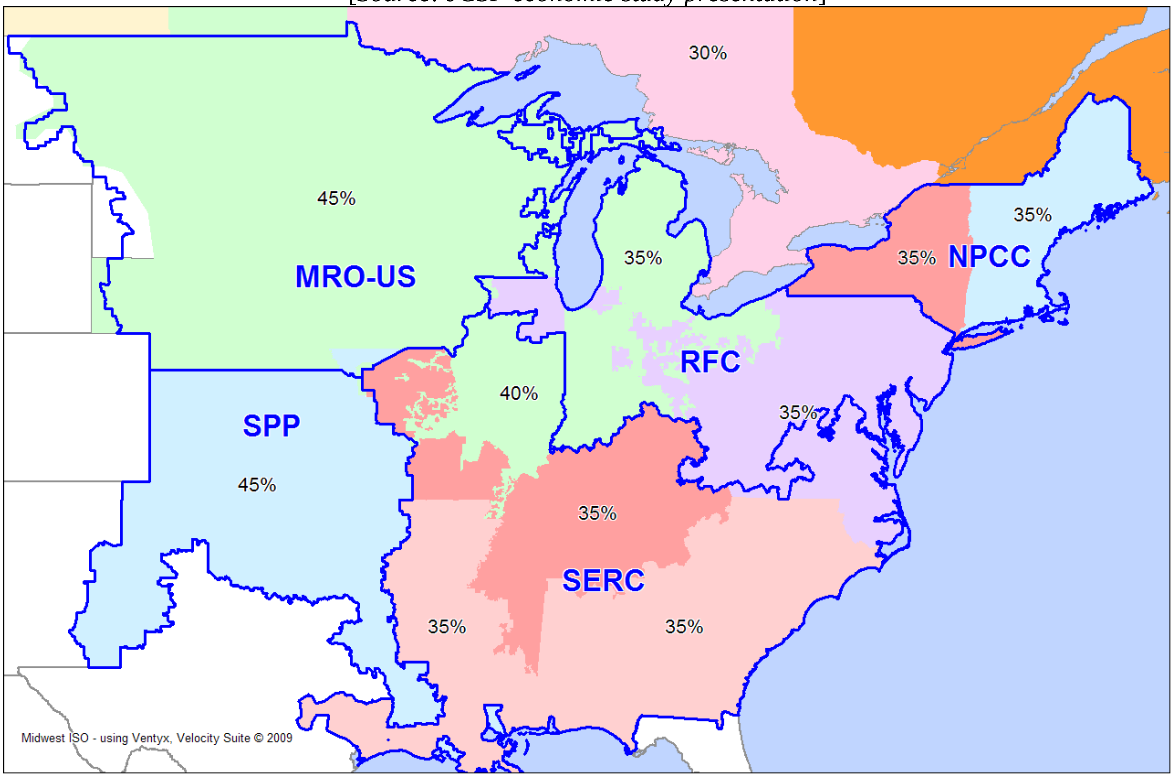
**Thematic Map of 11-Year Average Wind Energy Capacity Factors**




The map below shows the Regional energy capacity factors of future wind generators used in the JCSP economic study.

**JCSP Regional Energy Capacity Factors Used for Future Wind Generators**

[*Source: JCSP economic study presentation*]




The JCSP study also developed and analyzed the costs and benefits of conceptual transmission overlays for the two scenarios (reference and 20 percent wind energy). Both transmission overlays incorporate specific transmission projects that will contribute to the system's reliability needs for the ten-year period through 2018 and provide economic benefits in the 2024. These conceptual transmission overlays enabled the study of large-scale power transfers between different Regions of the country. The JCSP study did not evaluate the additional underlying lower voltage transmission network that will be necessary to connect the rest of the system.

Detailed maps showing the transmission overlays that were used in the JCSP study are located in the individual Regional Entity sections.

The figures below show the megawatt power flows between interfaces during the time of peak load for the JCSP footprint (August 1, 2024 16:00) with inclusion of each respective conceptual overlay. The JCSP was performed using an 8,760 hourly energy model. Figures X and Y represent only a single hour snapshot from the production cost model. Depending on outages and wind unit outputs, flows could significantly change from hour to hour. In the JCSP production cost model, units are dispatched based on security constrained economics. Because of this dispatch methodology, increased single hour flows in Figure Y, as compared to Figure X, are not necessarily a reflection of an increased amount of wind in the 20 percent case, but rather an increased capability to transfer low cost capacity to areas with higher load costs.

**Figure X: *Reference Case* Peak Load Megawatt Power Flows Between Interfaces**

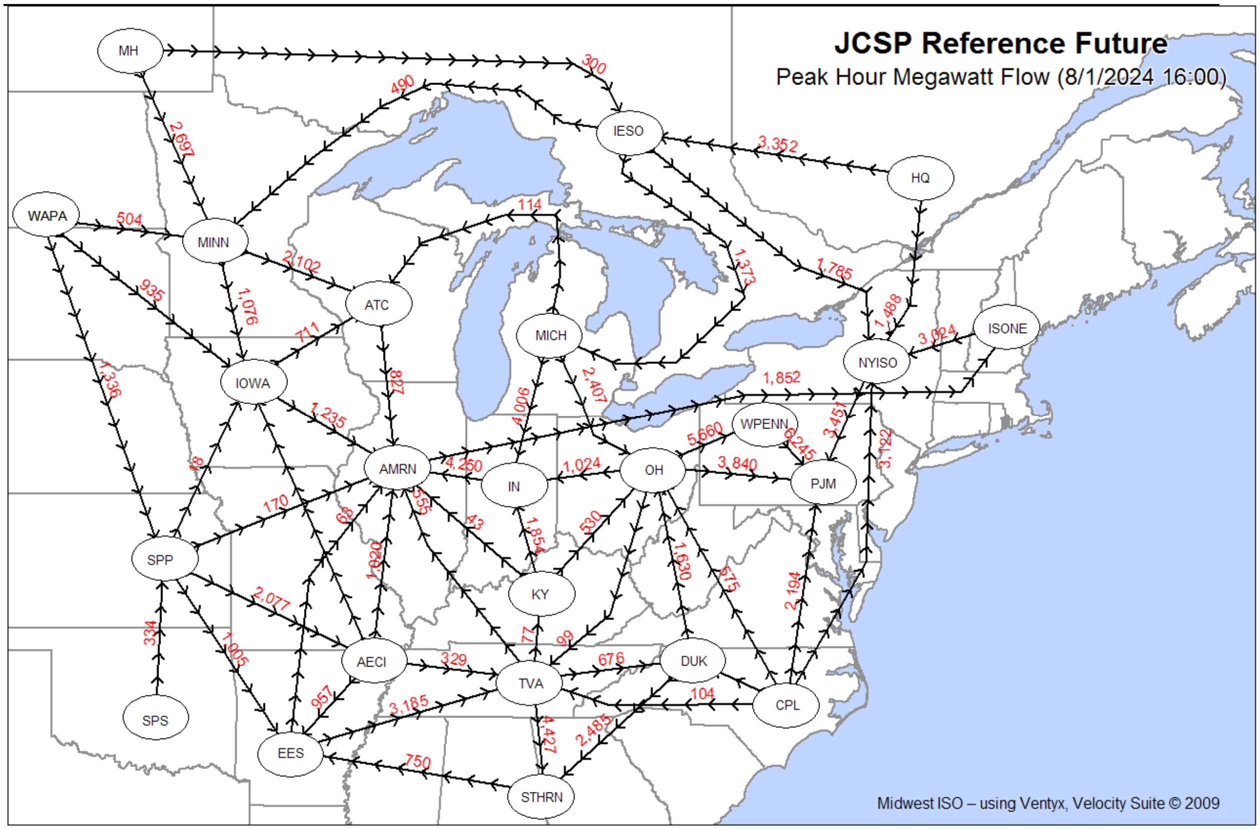
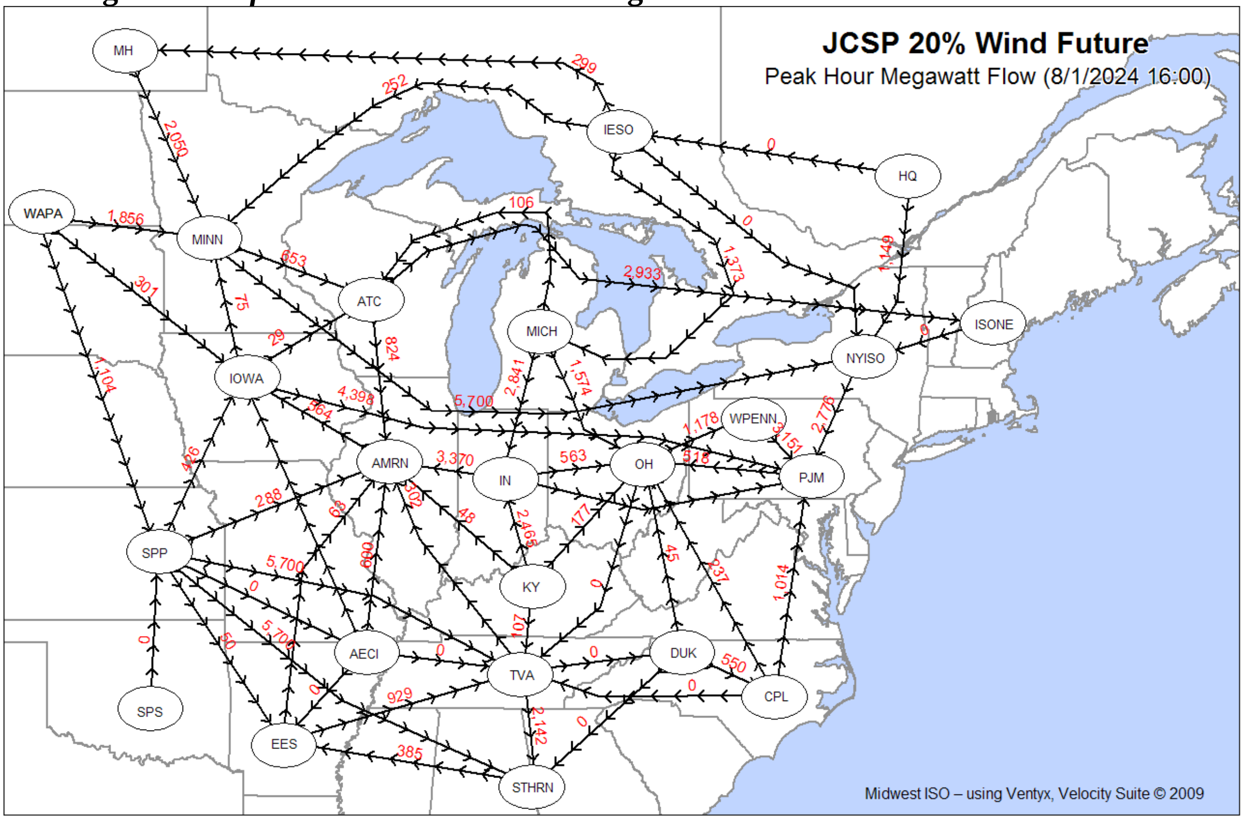

JCSP Reference Future
Peak Hour Megawatt Flow (8/1/2024 16:00)
MH
IESO
HQ
WAPA
MINN
ATC
MICH
NYISO
ISONE
IOWA
WPENN
AMRN
IN
OH
PJM
SPP
KY
AECI
TVA
DUK
CPL
SPS
EES
STHRN
Midwest ISO – using Ventyx, Velocity Suite © 2009

**Figure Y: *Reference Case* Peak Load Megawatt Power Flows Between Interfaces**




Additional Regional Entity specific details for this scenario assessment are found in each of the MRO, RFC, and SPP Regional sections.

# Scenario Letter

December 23, 2008

**REGIONAL MANAGERS**

| | | | |
|---|---|---|---|
| TRE | — Larry Grimm | RFC | — Timothy R. Gallagher |
| FRCC | — Sarah Rogers | SERC | — Gerry Cauley |
| MRO | — Daniel P. Skaar | SPP | — Charles H. Yeung |
| NPCC | — Edward A. Schwerdt | WECC | — Louise McCarren |

Dear Regional Managers:

***2009 Scenario Reliability Assessment Data Request***

The NERC Reliability Assessment Subcommittee (RAS) is requesting your assistance to assess the reliability of your Region. Based on NERC's Planning Committee direction, your Region provided a Scenario Study Outline in 2008 for one *Scenario Case* to be performed in 2009. These outlines were approved at the Planning committee's June 2008 meeting, and the studies have commenced thereafter.

NERC requests you send the data and results of this Regional *Scenario Case* assessment electronically in the attached Excel spreadsheets by **May 1, 2009** and the written Regional assessment narrative by **June 15, 2009** to john.moura@nerc.net, with copy to me at mark.lauby@nerc.net. Data and responses to the narrative questions (See Attachment I, which includes the draft schedule) should be as complete and accurate as possible based on available information as of the time of the submittal. The questions should be answered in the way that your Region, subregion, and/or province consider these items in its reliability assessment. Background of this *Scenario Case* analysis request and summary of responses from each Region is found in Attachment II.
Additionally, a few specifics:

- **Use the same capacity definitions for both the *Scenario Case* and *Reference Case* (whether the 2008 or 2009 LTRA *Reference Case* is used).** Ensure that comparison of resources can be made with the selected *Reference Case* by using the same capacity and demand categories for both cases.
- **Do not change the questions** when seeking input from stakeholders of your Region.
- **Annotate your responses** to the attached questions for easy identification by the peer reviewers. These annotations will be removed in the final report. Respond to all questions, and, if appropriate, explain why the response to the question is "not applicable."
- Follow the ***Reliability Assessment Narrative Format Guide*** provided separately. To improve the consistent look and feel of the report, *please do not copy and paste tables/charts, rather re-develop these materials ensuring the suggested templates are followed*.

Please contact us with any questions. On behalf of the Planning Committee and the Reliability Assessment Subcommittee, we wish to thank you for your support of NERC's reliability assessments.

Sincerely,

Mark G. Lauby
Manager, Reliability Assessments

MGL:ig
Attachments
cc: John Moura, Technical Analyst, NERC Reliability Assessments
Reliability Assessment Subcommittee
Planning Committee
Data Coordination Working Group

## Scenario Letter: Attachment I
## Scenario Narrative

### *Scenario Reliability Assessment* Schedule

Reliability Assessment Subcommittee has set the schedule below:

**2009**

| | |
|---|---|
| December 22 | Scenario Data and Narrative Request sent to Regional Entities |
| May 1 | Scenario data due to NERC |
| June 15 | Regional Assessment narrative due to NERC |
| July 10 | Draft Report sent to RAS |
| July 22-23 | RAS Peer Review *Scenario Case* comparison |
| August 15 | Draft to RAS |
| September | Draft to PC and MRC for review |
| Sept 24 | Final draft to NERC Board of Trustees |
| October 1 | Target release and electronic publication of report |

### Background

Development of a small set of *Scenario Cases* for comparison to a *Reference Case* is an extremely valuable way to understand the robustness of the *Reference Case* and to study potential *Scenario Case* impacts on bulk power system reliability.

The goal of the 2009 Scenario Narrative is to provide insights on the impacts of significant changes in system characteristics and reliability. The Regional/subregional responses, therefore, should compare the results of the 2008 or 2009 ten-year Scenario (here forward call the *Scenario Case*) and the 2008 or 2009 LTRA ten-year *Reference Case* (here forward call the *Reference Case*). The narrative outline and questions in this Attachment form the foundation for the Regional/subregional response to these comparisons. The background for this Scenario Analysis and summary of responses from each Region is found in Attachment II.

### Regional Scenario Self Assessment

Prepare a written assessment for your Region discussing any situations that could affect reliability for the next ten years — the write-up should be submitted in Microsoft Word format, following the ***Reliability Assessment Narrative Format-Guide,*** attached separately**.** To improve the consistent look and feel of the report, *please do not copy and paste tables/charts from other reports, rather re-develop these materials ensuring the suggested templates are followed.*

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

In an effort to add more consistency to the assessment report, all Regions are asked to follow the outline below in preparing their written assessment. Additionally, provide a one or two paragraph executive summary of the impact on reliability of the *Scenario Case* in your Region.

## Scenario Letter: Attachment II
## 2009 Scenario Analysis

All Regions must follow the outline below in preparing their written assessment.

*Attachment II to the 2009 Scenario Analysis letter included background material on the report. This material is presented in the About This Report section of this report.*

## Region

### Executive Summary

Provide a one or two paragraph executive summary of the expected Regional performance for the *Scenario Case* over the next ten years.

### Introduction

Introduce the Region and high level results.

a) Describe the *Reference Case* used contrast the *Scenario Case* to it.
b) Provide a comprehensive overview of the study and describe reliability impacts of the *Scenario Case* for your Region/subregion
c) Discuss significant assumptions
d) Review key issues and results compared to the *Reference Case*.

1. **Demand** (Only Identify Changes Resulting from Integration of New Resources)
    a) If different from the *Reference Case*, compare weather and economic assumptions upon which the *Scenario Case* forecast is based. If different from the *Reference Case*, compare the forecasts and discuss the key factors leading to any changes. Discuss any changes in growth rate and load variability.

    b) If different from the *Reference Case*, compare the *Scenario Case's* projected dispatchable, controllable demand response reducing peak demand — i.e. interruptible demand; direct control load management; critical peak pricing with control; load as a capacity resource, etc.

2. **Generation**
    a) Identify and compare the amount of capacity resources in-service or expected to be in-service during the study period (NOTE: Use consistent capacity classifications when comparing the *Reference Case*).
        **i.** Discuss the assumptions pertaining to when the resources are added over the ten-year time frame to support the *Scenario Case*. Identify the incremental changes to the *Reference Case* that are:
            (i) Variable (i.e. wind, solar, etc.) and their associated nameplate and capacity on-peak amounts compared and associated annual capacity factor.

(ii) Biomass (wood, wood waste, municipal solid waste, landfill gas, ethanol, and other biomass).[122].
(iii)Carbon Capture and Sequestration
(iv)Conventional resources (e.g. coal, gas, nuclear, etc.).

**ii.** Compare the *Scenario Case* and *Reference Case* generation mix for each seasonal peak over the ten-year time frame.

b) For Planned and Proposed capacity resources, what process is used to select resources to be included for reliability analysis/capacity margin calculations (i.e. forward capacity markets, obligation to serve activities, low certainty classes of resources under consideration, etc.)? Compare and discuss the differences between this *Scenario Case* and the *Reference Case* submittal.

## 3. Capacity Transactions on Peak

a) Purchases on Peak

i) Identify and quantify any purchases from other Regions and also those purchases between subregions that affect subregional capacity margins. Discuss how they differ from the *Reference Case* submittal. Categorize them as:

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

b) Sales on Peak

i) Identify and quantify any sales to other Regions and also those sales between subregions that affect subregional capacity margins. Discuss any differences to the *Reference Case*. Categorize them as:

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

c) Compare the reliance on outside assistance/external resources (clarify whether it is external to balancing area(s) or the Region) that the Regions/subregions requires for emergency imports and reserve sharing to the *Reference Case* submittal.

## 4. Transmission

b) Describe any new bulk power system transmission needed to be in-service o support the *Scenario Case*, compared to the *Reference Case*.

c) Provide a table, sorted by subregion, of significant transmission additions required to support bulk power reliability under this *Scenario Case*:

| Transmission Project Name | Voltage (kV) | Length (Miles) | In-service Date(s) | Description/Status |
|---|---|---|---|---|
| | | | | |

[122] ***Biomass:*** *Organic nonfossil material of biological origin constituting a renewable energy source.*

d) Provide a table, sorted by subregion, of significant transformer additions required to support bulk power reliability under this *Scenario Case:*

| Transformer Project Name | High-Side Voltage (kV) | Low Side Voltage (kV) | In-service Date(s) | Description/Status |
|---|---|---|---|---|
| | | | | |

e) Provide a listing of any other significant substation equipment (i.e. SVC, FACTS controllers, HVdc, etc.) additions that are different than the *Reference Case.*

## 5. Operational Issues (Known or Emerging)

Are there are potential operating issues different from the *Reference Case* which may impact reliability during the next ten years? Would you expect additional operating guides and/or changes in interface limits resulting from this *Scenario Case*?

## 6. Reliability Assessment Analysis

Describe the assessment process for the *Scenario Case* used by the Region and subregions. ***(Cite reports documenting the studies in a footnote or reference).***

a) Compare the projected capacity margins between the *Scenario Case* and the *Reference Case*. Also, compare them to the Regional, subregional, state, or provincial requirements.

i) If applicable, do the assumptions change between the two cases to establish the Regional/subregional capacity margin criteria or target margin level?

ii) Does the amount of resources internal to the Region or subregion that is relied on to meet the criteria, target margin level, or forecast load for the assessment period change when compared to the *Reference Case*?

iii) Does the amount of resources external to the Region/subregion that relied on to meet the criteria, capacity margins, target margin level or forecast load for the assessment period change when compared to the *Reference Case*?

iv) If performed, describe the resource adequacy studies (i.e. Loss-of-Load Expectation, Expected Unserved Energy, etc.) for the *Scenario Case*.

v) Discuss how resource adequacy changes between the *Scenario Case* and the *Reference Case*.

vi) Compare the resource adequacy of the *Scenario Case* and *Reference Case* if peak demands are higher than the 50/50 demand forecast in the *Reference Case*.

b) Compare unit retirements between the two cases and any potentially significant impact on reliability. What measures would have to be taken to mitigate the reliability concern?

c) Is there any difference in deliverability of resources between the *Scenario Case* and *Reference Case*? What might have to be done to ensure that the resources are sufficient and deliverable to meet your load requirements at the time of system peak?

d) If you are assuming substantial increase in wind penetration, how would you plan to address reactive and frequency response support requirements during ramping and wind variations.

e) Describe any anticipated changes to market structure, ancillary service requirements, etc., necessary to implement the *Scenario Case*.

f) Compare the fuel supply vulnerability in your Region/subregion between the *Reference Case* and the *Scenario Case*. If significant changes would result to your fuel mix compared with the *Reference Case*, please identify the changes and any impact that might have on potential fuel supply or delivery problems.

### 7. Other Region-Specific Issues that were not mentioned above

Describe any other significant differences between the *Scenario Case* and *Reference Case* assessments that might affect reliability over the ten-year study period.

### 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.

# Reliability Assessment Subcommittee Roster

| | | | |
|---|---|---|---|
| **Chair** | William O. Bojorquez<br>Vice President,<br>Planning | Hunt Transmission Services, L.L.C.<br>701 Brazos Street, Suite 970<br>Austin, Texas 78701–2559 | (512) 721–2653<br>(512) 721–2656 Fx<br>bbojorquez@hunttransmission.com |
| **Vice Chair** | Mark J. Kuras<br>Senior Engineer, NERC and Regional Coordination | PJM Interconnection, L.L.C.<br>955 Jefferson Avenue<br>Valley Forge Corporate Center<br>Norristown, Pennsylvania 19403–2497 | (610) 666-8924<br>(610) 666-4779 Fx<br>kuras@pjm.com |
| **ERCOT** | Dan Woodfin<br>Director, System Planning | Electric Reliability Council of Texas, Inc.<br>2705 West Lake Drive<br>Taylor, Texas 76574 | (512) 248–3115<br>(512) 248–4235 Fx<br>dwoodfin@ercot.com |
| **FRCC** | Vince Ordax<br>Manager of Planning | Florida Reliability Coordinating Council<br>1408 N. Westshore Boulevard<br>Suite 1002<br>Tampa, Florida 33607–4512 | (813) 207–7988<br>(813) 289–5646 Fx<br>vordax@frcc.com |
| **MRO** | Hoa Nguyen<br>Resource Planning Coordinator | Montana-Dakota Utilities Co.<br>400 North Fourth Street<br>Bismarck, North Dakota 58501 | (701) 222–7656<br>(701) 222–7970 Fx<br>hoa.nguyen@mdu.com |
| **NPCC** | John G. Mosier, Jr.<br>AVP-System Operations | Northeast Power Coordinating Council, Inc.<br>1040 Avenue of the Americas-10th floor<br>New York, New York 10018–3703 | (917) 697–8565 Cell<br>(212) 840–4907<br>(212) 302 –2782 Fx<br>jmosier@npcc.org |
| **RFC** | Jeffrey L. Mitchell<br>Director - Engineering | ReliabilityFirst Corporation<br>320 Springside Drive<br>Suite 300<br>Akron, Ohio 44333 | (330) 247–3043<br>(330) 456–3648 Fx<br>jeff.mitchell@rfirst.org |
| **RFC** | Bernard M. Pasternack, P.E.<br>Managing Director - Transmission Asset Management | American Electric Power<br>700 Morrison Road<br>Gahanna, Ohio 43230–8250 | (614) 552–1600<br>(614) 552–1602 Fx<br>bmpasternack@aep.com |
| **SERC** | Hubert C. Young<br>Manager of Transmission Planning | South Carolina Electric & Gas Co.<br>220 Operations Way<br>MC J37<br>Cayce, South Carolina 29033 | (803) 217–2030<br>(803) 933–7264 Fx<br>cyoung@scana.com |
| **SPP** | Mak Nagle<br>Manager of Technical Studies & Modeling | Southwest Power Pool<br>415 North McKinley<br>Suite 140<br>Little Rock, Arkansas 72205–3020 | (501) 614–3564<br>(501) 666–0346 Fx<br>mnagle@spp.org |
| **WECC** | James Leigh-Kendall<br>Manager, Reliability Compliance and Coordination | Sacramento Municipal Utility District<br>Mail Stop B305<br>P.O. Box 15830<br>Sacramento, California 95852–1830 | (916) 732–5357<br>(916) 732–7527 Fx<br>jleighk@smud.org |

| | | | |
|---|---|---|---|
| **WECC** | Bradley M. Nickell<br>Renewable Integration and Planning Director | Western Electricity Coordinating Council<br>615 Arapeen Drive, Suite 210<br>Salt Lake City, UT 84108 | (801) 455-7946<br>(720) 635-3817<br>bnickell@wecc.biz |
| **Canadian-At-Large** | Daniel Rochester, P. Eng.<br>Manager, Reliability Standards and Assessments | Independent Electricity System Operator<br>Station A, Box 4474<br>Toronto, Ontario, M5W 4E5 | (905) 855-6363<br>(416).574.4018 Cell<br>(905) 403-6932 Fx<br>dan.rochester@ieso.ca |
| **IOU & DCWG Chair** | K. R. Chakravarthi<br>Manager, Interconnection and Special Studies | Southern Company Services, Inc.<br>13N-8183<br>P.O. Box 2641<br>Birmingham, Alabama 35291 | (205) 257–6125<br>(205) 257–1040 Fx<br>krchakra@southernco.com |
| **LFWG Chair** | Yves Nadeau<br>Manager, Load and Revenue Forecasting | Hydro-Québec<br>Complexe Desjardins, Tour Est 25 étage --<br>Case postale 10000 Montréal, Québec H5B 1H7 | (514) 879–4100 ext 6131<br>nadeau.yves@hydro.qc.ca |
| **ISO/RTO** | Jesse Moser<br>Manager-Regulatory Studies | Midwest ISO<br>P.O. Box 4202<br>Carmel, IN 46082–4202 | (612) 718–6117<br>jmoser@midwestiso.org |
| **ISO/RTO** | John Lawhorn, P.E.<br>Director, Regulatory and Economic Standards Transmission Asset Management | Midwest ISO, Inc.<br>1125 Energy Park Drive<br>St. Paul, Minnesota 55108 | (651) 632–8479<br>(651) 632–8417 Fx<br>jlawhorn@midwestiso.org |
| **ISO/RTO** | Peter Wong<br>Manager, Resource Adequacy | ISO New England, Inc.<br>One Sullivan Road<br>Holyoke, Massachusetts 01040–2841 | (413) 535–4172<br>(413) 540–4203 Fx<br>pwong@iso-ne.com |
| **FERC** | Keith N. Collins<br>Manager, Electric Analysis Group | Federal Energy Regulatory Commission<br>888 First Street, NE<br>Washington, D.C. 20426 | (202) 502-6383<br>(202) 219-6449 Fx<br>keith.collins@ferc.gov |
| **FERC** | Sedina Eric<br>Electrical Engineer, Office of Electric Reliability, Division of Bulk Power System Analysis | Federal Energy Regulatory Commission<br>888 First Street, NE, 92–77<br>Washington, D.C. 20426 | (202) 502–6441<br>(202) 219–1274 Fx<br>sedina.eric@ferc.gov |
| **DOE** | Patricia Hoffman<br>Acting Director Research and Development | Department of Energy<br>1000 Independence Avenue<br>SW 6e–069<br>Washington, D.C. 20045 | (202) 586–1411<br>patricia.hoffman@hq.doe.gov |
| **Alternate SERC** | Herbert Schrayshuen<br>Director Reliability Assessment | SERC Reliability Corporation<br>2815 Coliseum Centre Drive<br>Charlotte, North Carolina 28217 | (704) 940–8223<br>(315) 439–1390 Cell<br>hschrayshuen@serc1.org |

| | | | |
|---|---|---|---|
| **Alternate FRCC** | John E. Odom, Jr.<br>Vice President of Planning and Operations | Florida Reliability Coordinating Council<br>1408 N. Westshore Blvd.<br>Suite 1002<br>Tampa, Florida 33607 | (813) 207–7985<br>(813) 289–5646 Fx<br>jodom@frcc.com |
| **Alternate MRO** | John Seidel<br>Reliability Assessment Manager | Midwest Reliability Organization<br>2774 Cleveland Ave<br>Roseville, Minnesota  55113 | (651) 855–1716<br>(651) 855–1712 Fx<br>ja.seidel@midwestreliability.org |
| **Alternate MRO** | Salva R. Andiappan<br>Principal Engineer | Midwest Reliability Organization<br>2774 Cleveland Ave<br>Roseville, Minnesota 55113 | (651) 855–1719<br>(651) 855–1712 Fx<br>sr.andiappan@midwestreliability.org |
| **Alternate RFC** | Paul D. Kure<br>Senior Consultant, Resources | Reliability*First* Corporation<br>320 Springside Drive<br>Suite 300<br>Akron, Ohio 44333 | (330) 247–3057<br>(330) 456–3648 Fx<br>paul.kure@rfirst.org |
| **Alternate SPP** | Alan C. Wahlstrom<br>Lead Engineer, Compliance | Southwest Power Pool<br>16101 La Grande Drive<br>Suite 103<br>Little Rock, Arkansas 72223 | (501) 688–1624<br>(501) 664–6923 Fx<br>awahlstrom@spp.org |
| **Member** | Jerry D. Rust<br>President | Northwest Power Pool Corporation<br>7505 N.E. Ambassador Place<br>Portland, Oregon 97220 | (503) 445–1074<br>(813) 445–1070 Fx<br>jerry@nwpp.org |
| **Member** | James Useldinger<br>Manager, T&D System Operations | Kansas City Power & Light Co.<br>PO Box 418679<br>Kansas City, Missouri, 64141 | (816) 654–1212<br>(816) 719–9718 Fx<br>jim.useldinger@kcpl.com |
| **Observer** | Stan Kaplan<br>Specialist in Energy Policy | Congressional Research Service<br>101 Independence Avenue, SE<br>Washington, D.C. 20540–7450 | (202) 707–9529<br>(301) 452–1349 Fx<br>skaplan@crs.loc.gov |

# North American Electric Reliability Corporation Staff Roster

North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Telephone: (609) 452-8060
Fax: (609) 452-9550

### Reliability Assessment and Performance Analysis

| | | |
|---|---|---|
| Mark G. Lauby | Director of Reliability Assessment and Performance Analysis | mark.lauby@nerc.net |
| Jessica Bian | Manager of Benchmarking | jessica.bian@nerc.net |
| Aaron Bennett | Engineer of Reliability Assessments | aaron.bennett@nerc.net |
| John Moura | Technical Analyst, Reliability Assessment | john.moura@nerc.net |
| Rhaiza Villafranca | Technical Analyst, Benchmarking | rhaiza.villafranca@nerc.net |

to ensure
the reliability of the
bulk power system