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Reliability Assessment Guidebook

Background

The NERC Planning Committee agreed at their February 2008 meeting that a Reliability Assessment Guidebook should be developed to support the enhancement of seasonal and long-term reliability assessments. The goals of this Guidebook are to:

- Improve consistency and transparency of assessments
- Increase granularity in assessments
- Outline the process to assess emerging industry issues
- Provide a core framework for conducting comprehensive and independent assessments

This Guidebook will be a reference for regional entities and registered entities, and is organized to clarify reliability assessment expectations and objectives. The intent is to document expectations and provide a comprehensive outline for reliability assessments. The guidebook will include the elements and issues that go into making the overall reliability assessment and final report as consistent, uniform and credible as possible by ensuring:

1. Regional Entities are approaching and delivering assessments and analysis more uniformly, so that external audiences (e.g., FERC, media, Congress, CEOs, etc.) can extract a clear understanding about the anticipated performance, strength and concerns of the bulk-power system over seasonal and long-term periods.

2. NERC’s and the Regional Entities’ assessments are presented in a consistent and conforming manner, so the overall report is effectively comprehensive and complete.

The Regional Entities will develop the foundation and support for the conclusions presented, and as such, the Guidebook articulates the corresponding foundation, support and conforming requirements for the NERC independent review, providing a uniform delivery of the reliability assessment.

Preliminary Development Process

1) Reliability Assessment Guidebook Task Force:

- Tom Burgess (Chair),
- Jeff Mitchell (RFC),
- WECC representative
- ERCOT representative
- Mark Lauby (NERC)

2) Contracted industry experts to support activity and a technical writer, if required

3) Communication with Stakeholders:

- Monthly updates with Planning Committee, Subcommittee Chairs, and stakeholders who contribute to the success of reliability assessment
NERC Reliability Assessment

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

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight regional areas. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada and a portion of Baja California, Mexico.

NERC’s primary role in providing reliability assessment is to identify areas of concern to the reliability of the North American bulk power system and to make recommendations for their remedy. NERC cannot order construction of additional generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Energy Policy Act of 2005². In addition, NERC does not make any projections or draw any conclusions regarding expected

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¹ On June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards with all U.S. owners, operators, and users of the bulk power system, and made compliance with those standards mandatory, as opposed to voluntary. NERC has similar authority in Ontario and New Brunswick, and is seeking to extend that authority to the other Canadian provinces. NERC will seek recognition in Mexico once the necessary legislation is adopted.


Reliability Assessment Guidebook - Outline
May 2008
electricity prices or the efficiency of electricity markets. The enclosed Special Reliability Assessment provides a high-level view of future resource adequacy.

The Seasonal and Long-Term Reliability Assessment provide key findings, a high-level assessment of future resource adequacy, an overview of projected electricity demands and demand response resources, planned and proposed generation and transmission additions, emerging issues and their potential reliability impacts, operational reliability trends, regional assessment highlights, scenario analysis update and regional self-assessments. The report represents NERC’s independent judgment of the reliability and adequacy of the bulk power system in North America for the coming ten years. NERC’s primary purpose in preparing this assessment is to identify areas of concern regarding the reliability of the North American bulk power system and to make recommendations to itself and others for their remedy.

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

Assessment Preparation

NERC prepares the Seasonal and Long-Term Reliability Assessment with support from the Reliability Assessment Subcommittee (RAS) under the direction of NERC’s Planning Committee (PC). The reports are based on data and information submitted by each of the eight regional entities submitted in March, May and September each year and periodically updated throughout the process. Any other data sources consulted by NERC staff are identified in the report.

NERC uses an active peer review process in developing its reliability assessments, which takes full advantage of industry subject matter expertise from all sectors of the industry. This process also provides an essential check and balance for ensuring the validity of the data and information provided by the regional entities.

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3 Section 39.11(b) of the U.S. FERC’s regulations provide that: “The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission.”

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

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

6 See http://www.nerc.com/~members/reliability_concepts/documents.htm for more background on reliability concepts used in this report.
Each regional self-assessment is assigned to two or three subcommittee members from other regions for an in-depth and comprehensive review. Reviewer comments are discussed with the regional entity’s representative and refinements and adjustments are made as necessary. The regional self-assessments are also subjected to scrutiny and review by the entire subcommittee. This review ensures members of the subcommittee are fully convinced that each regional self-assessment is accurate, thorough, and complete. The entire document, including the regional self-assessments, is reviewed by the PC/OC and the Member Representatives Committee (MRC). At the conclusion of this process, NERC management reviews the assessment results in detail before the report is submitted to the NERC Board of Trustees for final approval.

In the *Seasonal and Long-Term Reliability Assessments*, the baseline information on future electricity supply and demand is based on several assumptions:

- Supply and demand projections are based on industry forecasts submitted. Any subsequent demand forecast or resource plan changes may not be fully represented.
- Peak demand and capacity margins are based on average weather conditions and assumed economic activity. Weather variability is discussed in each regional self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Planned outages and additions/upgrades of generation and transmission will be completed as scheduled.
- Demand reductions expected from demand response programs will be effective, if and when they are called on.
- Other peak demand-side management programs are reflected in the forecasts of net internal demand.
- Firm electricity transfers between regions are contractually arranged and occur as projected.

The demand and supply data collection process is shown in Chart 1 below. All NERC Regions, including Canada and Mexico, provide their capacity information to NERC through the LTRA data collection process, which is then provided to EIA through the EIA-411 Data. Generator Owners and Operators provide specific generator data to EIA through the EIA-860 Data, which is then provided to NERC. Once all data is compiled, it is used to populate the Electricity Supply & Demand database.
A high level annual schedule for annual reliability assessments is shown in Figure 1:
Figure 1: Reliability Assessment Schedule
Demand and Load Forecasting

Demand
The peak demand projections represent an aggregate of weather-normalized regional projections. In some cases, these regional aggregations do not take into account the regional diversity among the various regional participants’ peak demands, which, depending on the geographical size, could significantly influence the reserve margin comparisons. However, in other cases, as regions can be wide-spread, resources would not be deliverable, and sub-regional analysis is more meaningful. The following defines demand terms used in NERC’s reliability assessments.

**Total Internal Demand:** Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).

**Standby Demand:** The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer’s primary source. Standby Demand is intended to be used infrequently by any one customer.

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

A question is whether or not Regions count all DR capacity or adjust DR using some sort of methodology due to the fact that limitations exist on the ability to curtail “non-firm” load or it is conceivable that customers may not respond when requested.

Load Forecasting
Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or **midpoint.** Each NERC's Region Member is responsible to provide demand forecasts for the long term Reliability Assessment. Each regional demand forecast, for example, is assumed to represent the expected **midpoint** of possible future outcomes. This means that a future year’s actual demand may deviate from the midpoint projections due to variability in key factors that drive electrical usage. In the case of the NERC regional forecasts, there is generally a **long-run** 50% probability that actual demand will be higher than the forecast midpoint and a **long-run** 50% probability that it will be lower.
For securing energy supply or ensuring reliability of the bulk power system, adequate risk management implies defining possible future outcomes and their probability of occurrence. For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, the NERC Load Forecasting Working Group (LFWG) develops upper and lower 10% confidence bands around the NERC regional peak demand and energy forecasts. This means that there is a long-run 80% probability that future demand and energy will occur within these bands. Conversely, there is a 10% chance that future outcomes could be less than the lower band, and a 10% chance that future outcomes could be higher than the upper band.

Overview of Method - LFWG continued to introduce enhancements to the regional bandwidth methods. The previous method used first order autoregressive models for every region’s energy, summer peak, and winter peak. Although using a single statistical time-series model has merits and results were satisfactory, LFWG desired to investigate other approaches and model specifications for possible improvements or better model fits. The study by Brisson & Nadeau\(^7\) recommended an approach to find an optimal model for each Region and each series (energy, summer peak, winter peak).

It leads to an automated model selection procedure based on minimizing the Schwarz Bayesian Information Criterion (BIC) statistic. [BIC = n * ln(MSE) + k * ln(n) ], where “MSE” = “(SSE/n)” is the mean squared errors, “n” is the number of observations, and “k” is the number of parameters. The study looked at a variety of univariate time-series models including simple ARIMA models, the original first order autoregressive model, a first order moving average model, and random walk, with and without drift. The study also looked at a linear trend, simple exponential smoothing, and other smoothing techniques such as Holt, Holt/Winters, and damped exponential. Results from Brisson in May, and the current work by LFWG, indicate candidate models can be limited to the four simple ARIMA type models, since in both cases the method selected only those models.

<table>
<thead>
<tr>
<th>No.</th>
<th>Candidate Model</th>
<th>Form</th>
<th>ARIMA (p,d,q) Notation</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Random Walk with drift</td>
<td>[y_t = \mu + y_{t-1} + \epsilon_t]</td>
<td>(0,1,0) with Intercept</td>
<td>17</td>
</tr>
<tr>
<td>2</td>
<td>Random Walk without drift</td>
<td>[y_t = y_{t-1} + \epsilon_t]</td>
<td>(0,1,0) without Intercept</td>
<td>4</td>
</tr>
<tr>
<td>3</td>
<td>Moving Average</td>
<td>[y_t = \mu + \epsilon_t + \theta y_{t-1}]</td>
<td>(0,1,1) with Intercept</td>
<td>7</td>
</tr>
<tr>
<td>4</td>
<td>Autoregressive</td>
<td>[y_t = \mu + \rho y_{t-1} + \epsilon_t]</td>
<td>(1,1,0) with Intercept</td>
<td>5</td>
</tr>
</tbody>
</table>

The principal features of the regional bandwidth method include:

1. The regional projections of demand and net energy for load are modeled as a function of past peak demand or energy. An optimal model is selected for each region’s energy, summer peak, and winter peak (33 models in all).

The most frequent (17 out of 33) optimal model was the random walk model with drift specification. This approach expresses the current value of the time series as a linear function of the previous values of the series and a random shock. The functional form is:

\[ y_t = \mu + y_{t-1} + \epsilon_t \]

where \( \mu \) is a constant term. The shocks \( \epsilon_t \) are random errors or white noise and are assumed to be normally and independently distributed with mean zero, constant variance, and \( \sigma_\epsilon^2 \) independent of \( y_{t-1} \).

In cases where membership changes resulted in significant changes to a region’s energy and load, an intervention variable is added to the equation to allow the bandwidths to suitably depict post-change energy and load uncertainty. The historic variability observed in demand and energy is used to develop uncertainty bandwidths projections. Variability, represented by the variance \( \sigma_\epsilon^2 \) of the historic data series, is combined with other model information to derive the uncertainty bandwidths unique to each regional projection.

Each of the eight US and three Canadian regions is modeled separately with three regions segmented into their United States and Canadian counterparts. Irregular patterns of deregulation, different economic trends, and variable weather patterns contribute to the variability of actual peak demand and electricity usage. The response to these factors differs across regions due to different weather variation, economic conditions, energy prices, and regulation/deregulation policies. The bandwidths around NERC regional projections of long-term peak demand forecasts implicitly reflect the combined uncertainty from these factors. Accordingly, the bandwidth results on a region-by-region basis are unique.

Results - The bandwidths produced are theoretical bandwidths based on mathematical representations of the series. They are derived from in sample residuals (fitting errors) and 80% standard normal confidence intervals. Bandwidths obtained with the theoretical formulas are then proportionally projected onto the regional forecasts provided by the Regions.

The table below shows the optimal model for each region based on the BIC statistic. The graphical and numerical results of the bandwidth analyses follow in table below:

<table>
<thead>
<tr>
<th>Table &amp; Figure</th>
<th>Region</th>
<th>Net Energy for Load</th>
<th>Summer Demand</th>
<th>Winter Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ERCOT</td>
<td>RW with drift</td>
<td>RW with drift</td>
<td>RW with drift</td>
</tr>
<tr>
<td>2</td>
<td>FRCC</td>
<td>RW with drift</td>
<td>Autoregressive</td>
<td>Autoregressive</td>
</tr>
<tr>
<td>3</td>
<td>MRO-US</td>
<td>RW with drift</td>
<td>RW without drift</td>
<td>Autoregressive</td>
</tr>
<tr>
<td>4</td>
<td>NPCC-US</td>
<td>RW with drift</td>
<td>RW without drift</td>
<td>RW without drift</td>
</tr>
<tr>
<td>5</td>
<td>RFC</td>
<td>RW with drift</td>
<td>Autoregressive</td>
<td>RW without drift</td>
</tr>
<tr>
<td>6</td>
<td>SERC</td>
<td>RW with drift</td>
<td>RW with drift</td>
<td>RW with drift</td>
</tr>
<tr>
<td>7</td>
<td>SPP</td>
<td>RW with drift</td>
<td>Autoregressive</td>
<td>RW with drift</td>
</tr>
<tr>
<td>8</td>
<td>WECC-US</td>
<td>Moving Average</td>
<td>Moving Average</td>
<td>Moving Average</td>
</tr>
<tr>
<td>9</td>
<td>MRO-Can</td>
<td>RW with drift</td>
<td>Moving Average</td>
<td>Moving Average</td>
</tr>
</tbody>
</table>

During the 1990s and 2000s several regions including MAIN, MAPP, MRO, RFC, SERC and SPP experienced changes in membership and geography. The historical net energy and peak load data and figures depict these changes.
The traditional method for choosing or “identifying” the correct form of an ARIMA model is to visually examine the autocorrelation and partial autocorrelation functions of the data series. Doing this for the energy series results in the same outcome as the optimization method for all cases where the Random Walk with drift model is optimal. Where the optimization method chose an MA model for WECC-US energy, visual identification indicates a toss-up between the MA and AR models.

**Demand Side Management**

Demand-Side Management (DSM) is an important ingredient of an overall portfolio of resources required to meet the increasing demands for electricity in North America. DSM is often understood to include two components: energy efficiency (EE) and demand response (DR). EE is designed to reduce electricity consumption during all hours of the year, attempting to permanently reduce the demand for energy in intervals ranging from seasons to years and concentrates on end-use energy solutions. DR is designed to change on-site demand for energy in intervals from minutes to hours and associated timing of electric demand/energy use (i.e., lowering during peak periods) by transmitting changes in prices, load control signals or other incentives to end-users to reflect existing production and delivery costs.

DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand. They can be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources. NERC’s 2006 Long-term Reliability Assessment (LTRA) noted:

> Demand reductions have been achieved through various demand response programs. Direct control load management and interruptible demand programs represent about 2.5 percent of summer peak demand (20,000 MW) in the U.S. and about 2.5 percent of winter peak demand (2,500 MW) in Canada. New or expanded demand response programs and initiatives can further reduce peak demands.

The 2007 LTRA mentions:

> Demand response is increasingly viewed as an important option to meet the growing electricity requirements in North America, while at the same time

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10 See Appendix III Glossary for definitions of terms used in this report.
As the industry’s use of Demand-Side Management evolves, NERC’s data collection and reliability assessment need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC’s seasonal and long-term reliability assessments currently assume projected EE programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect demand response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Demand Side Management involves all activities or programs undertaken to influence the amount and timing of electricity use.

Figure 1 provides a graphic illustration of DSM categories.
Figure 1: Demand-Side Management and NERC’s Data Collection

Note the context of the definitions is demand-side management, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. Many of the demand response categories are defined below support Figure 1.

**Energy Efficiency**: permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally it results in reduced consumption across all hours rather than event-driven targeted load reductions.

**Demand Response**: changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

**Dispatchable**: demand-side resource curtails according to instruction from a control center

**Controllable**: dispatchable demand response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints

**Capacity**: demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance

**Direct Control Load Management**: demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

**Contractually Interruptible (Curtailable)**: curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council’s seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

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

**Load as a Capacity Resource**: demand-side resources that commit to pre-specified load reductions when system contingencies arise.
**Ancillary**: demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance

**Non-Spin Reserves**: demand-side resource not connected to the system but capable of serving demand within a specified time

**Spinning/Responsive Reserves**: demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

**Regulation**: demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin

**Energy-Voluntary**: demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized

**Emergency**: demand-side resource curtails during system and/or local capacity constraints

**Non-dispatchable**: demand-side resource curtails according to tariff structure, not instruction from a control center

**Time-Sensitive Pricing**: retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods

- **Time-of-Use (TOU)**: rate and/or price structures with different unit prices for use during different blocks of time
- **Critical Peak Pricing (CPP)**: rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours
- **Real Time Pricing (RTP)**: rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis

**System Peak Response Transmission Tariff**: rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges
Understanding Energy Efficiency (EE) - The benefits and characteristics of EE have been well studied and documented. In addition to energy savings, EE may reduce peak demand and defer the need for new investments.

There are a variety of ways for energy efficiency to be measured. The most straightforward method is to use the expected, or average, impact. In some cases, a more conservative measure may be used de-rating energy efficiency impacts for uncertainty in load reduction (the “dependable” reductions). Successful integration of energy efficiency into resource planning requires close coordination between those responsible for energy efficiency and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives.

NERC currently obtains forecast internal demand data for summer/winter peaks. Determining the effects of energy efficiency on peak internal demand can provide a measure of reliability benefits.

Different energy efficiency programs (industrial, commercial and residential) may have variable influence on total capacity (MW) reduction depending on the time of day reduction is desired. Load forecasting is a critical component to understand the overall peak reduction observed or expected. Tracking and validating energy efficiency programs is vital to increase the accuracy of forecasts.

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**Understanding Energy Efficiency**

To incorporate energy efficiency into resource planning, the energy efficiency peak demand reduction must be defined so resource planners can evaluate it along with capacity resources. Care must be exercised, to assure that the estimates are not misused for other applications. For example, a peak value may be developed for a transmission study based on the energy efficiency reduction during the 12 monthly peaks, but then misused in a generation planning application with a single annual peak.

Analysts can use the same engineering or statistical models developed for producing energy reduction estimates (assuming that the model has sufficient hourly information to match the peak definitions). It is incorrect to assume the largest demand reduction from an energy efficiency measure occurs during peak demand. The coincident peak reduction is generally lower than the non-coincident peak reduction:

1. The timing of the largest reduction does not match the timing of the utility peak,
2. Not all measures will be operating at the time of the peak (people are not home), and
3. Equipment not installed or maintained properly.

In addition, there are synergistic affects that can increase or decrease the reductions depending upon other energy efficiency measures.

Percentage energy savings is not the same as percentage demand savings. For example, in California, SEER was used as the primary measure of AC unit efficiency. Codes and standards were written to promote high SEER units in the state, with the untested expectation that the more efficient unit would also help reduce capacity needs. Many manufacturers responded to the SEER metric with high SEER units that had two compressors and may result in a higher peak demand.

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Understanding Demand Response - Demand Response (DR) programs have been in use for many years, providing more direct control to system operators. In addition, high performance factors are emerging from demand response providers not using direct control methods. The influence of DR on reliability concentrates on peak demand reduction, periods of high wholesale prices, or low-reserve conditions rather than on reductions in overall energy consumption.

Long-term reliability benefits include reduced supply-side and transmission requirements at time of peak or other times when resource availability is reduced. Additionally, DR supports the management of operational reserves/flexibility as well as long-term planning reserves.

All DR resources may benefit overall system reliability, though some DR options benefit system reliability more than others. The most dependable DR are dispatchable provided by load resources under contractual obligation to perform, subject to dispatch by grid operators, and required to meet measurement & verification standards consistent with their importance to grid reliability.

Some DR options can have more reliability benefits than conventional supply-side peaking resources such as a combustion turbine generators ("CTG"). The reliability benefits of DR are a function of, among other things, any limits on annual interruptions, the frequency of interruptions, the duration of interruptions, the ramp-up time to reduce load, and penalties or sanctions for non-performance.

Many large end-users have the necessary metering and telemetry equipment capable of providing demand response for many years. The cost of advanced metering and telemetry does not appear to be a significant barrier to increasing their participation; rather, DR design is an extremely important consideration when decisions for investments are made. Expanding DR to smaller customers can require investment in technologies to assure adequate measurement and verification of the load response, including advanced metering, load curtailment technologies, and two-way customer communications. Such investments must be recognized along-side other investments as part of overall bulk power system rejuvenation.

DR programs are further classified as Dispatchable and Non-Dispatchable. Increased predictability of customer participation and load response, especially for voluntary programs, is vital to understand the influence of DR on reliability.

Dispatchable Demand Response (D²R) - D²R includes an inducement or incentive for customer participation and peak load reductions. D²R have been used for many years, increasing direct control to system operators and can provide Capacity, Ancillary services and Emergency energy with a high degree of certainty. NERC currently collects Direct Load Control and Interruptible Demand as part of its seasonal and long-term reliability assessments.
The following categories of D²R are considered:

Dispatchable Controllable Demand Response (DCDR)
- Capacity
  1) Direct Load Control
  2) Interruptible Demand
  3) Critical Peak Pricing with Control
  4) Load as a Capacity Resource
- Ancillary Load Reduction Acting as Capacity
  1) Spinning Reserves
  2) Non-Spinning Reserves
  3) Regulation
- Energy-Voluntary
  1) Emergency

Dispatchable Economic Demand Response (DEDR)
- Energy-Price
  1) Demand Bidding and Buy-Back

The DCDR dispatchable resources provide an active tool for load-serving entities, electric utilities or grid operators to manage their costs and maintain operational reliability.

**Non-Dispatchable Demand Response (ND²R)** - ND²R link prices in retail and wholesale markets. Retail consumers obtain a price signal reflecting the costs of production and delivery providing a signal to deploy resources more efficiently. This characteristic, as ND²R is generally tailored for mass markets, has the potential to reduce or shape electricity use and overall costs.

Voluntary demand response triggered by high energy prices can have reliability benefits if the high prices predictably correlate to scarcity conditions or grid disturbances. Similarly, in cases where customers’ transmission & distribution charges are based on their consumption during system peaks, economic demand response actions taken to lower those charges can have direct and positive impacts on reliability. Such price-based demand response is often undertaken unilaterally by customers — that is, not subject to operator dispatch and potentially taken without the involvement or knowledge of the load-serving entity. This can complicate efforts to measure the quantity and quality of the reliability benefits of price-based DR.

The following categories of ND²R are considered:

**Time-Sensitive Pricing**
- Time-Of-Use (TOU)
- Critical Peak Pricing (CPP)
- Real-Time Pricing (RTP)
- System Peak Response; Transmission Tariff
Voluntary demand response triggered by high energy prices can have reliability benefits if energy prices can predictably correlate to scarcity conditions or grid disturbances. Similarly, in cases where customers’ delivery charges are based on their consumption during system peaks, economic demand response actions taken to lower these charges can have direct and positive impacts on reliability.

Such price-based demand response is often undertaken unilaterally by customers — that is, not subject to operator dispatch and potentially taken without the involvement or knowledge of the load-serving entity. The unpredictable quantity and quality of ND²R reliability benefits has created a barrier as certainty is a critical characteristic which will require measurement.
Supply

Supply is a critical component of reliability assessments because it allows NERC and others to assess whether or not reporting entities have or project enough supply to be able to serve load. Supply can be of many forms including, but not limited to, nuclear, fossil, solar, wind, and hydro. Some entities also consider certain DSM programs as supply resources.

The NERC Regions consist of entities with FERC approved organized markets and traditional markets. The entities within these different markets treat supply/capacity differently as it relates to reliability assessments and capacity margin calculations. For example, as it relates to resources:

- ERCOT may consider all existing and operable resources to be available to serve the market and include them in capacity margin calculations. Any undeliverable capacity due to transmission constraints is managed through congestion management.
- PJM includes all capacity resources in the capacity margin calculations. All other existing resources are not included in the capacity margins.
- Most subregions in SERC consider only those resources that are deliverable and designated by a load serving entity for inclusion in the capacity margin calculations. All other existing resources are excluded from the capacity margin calculations.

As such, there is a considerable amount of on-the-ground generation that may not be accounted for in any calculations reported by certain regions. This issue becomes even more complex for long term capacity margin assessments because of the uncertainty involved in what generation gets built and how each region accounts for future resources. Recognizing these differences between various market structures for the reporting entities, NERC has developed various definitions and categories of supply, purchases, and sales that provides for granularity needed to perform computation of supply metrics to understand reliability trends for various NERC Regions. Future reliability assessments may require additional transparency and granularity as it relates to supply/capacity to assess short term and long term reliability.

a) Supply resources (for nuclear, thermal, hydro and variable resources)

i) Capacity versus nameplate

(1) Generator Nameplate Capacity is defined as the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

(2) Generator Capacity is defined as the maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress. Generator Capacity is the capacity expected to be available to supply electric load.
(3) Generator Capacity should be reported by each reporting entity. In general, Generator Capacity is less than the Generator Nameplate Capacity; however, if the Generator Capacity is greater than the Generator Nameplate Capacity, the reporting entity should provide an explanation(s).

ii) Energy-only

(1) Energy-only resources are resources interconnected to the transmission grid and are eligible to deliver their output using the existing firm or non-firm capacity of the transmission grid on an “as available” basis. In bid-based markets, Energy-only resources can bid to sell into such market. In all other areas, Energy-only resources are not assured firm delivery service; however, such resource may obtain point-to-point transmission service or gain access to secondary network transmission service. Energy-only resources are designated as energy-only or have elected to be classified as energy-only (may include generating capacity that can be delivered within the area but may be recallable to another area).

(2) In non-organized markets, energy-only resources are reported in reliability assessments and potential capacity, but are not counted in margin calculations unless such resource(s) has firm delivery service. In organized markets, energy-only resources are reported in reliability assessments as potential capacity and may be counted in margin calculations if such resource(s) are reasonably expected to be able to deliver their output to the transmission grid. For example, if an energy-only resource has shown the ability to be designated on a short-term basis in a bid-based market, such resource is considered deliverable and counts in margin calculations. An adjustment may be made to energy-only resource capacity to account for uncertainties in being able to rely on such capacity to serve load.

iii) Mothballed

(1) Mothballed capacity is defined as generation capacity for which the owner/operator has suspended operations, but has not decided to retire such capacity. Mothballed capacity can be returned to an operational state.

(2) Mothballed capacity that may be returned to service during the period of the assessment should be reported as “Existing, Other”. Mothballed capacity not expected to be returned to service during the period of the assessment should be reported as “Existing, but Inoperable”.

iv) Inoperable

(1) Inoperable capacity is defined as generating capacity that is totally or partially out of service at the time of system peak load, either for maintenance outages or planned outages. Also included are reasons such as: environmental restrictions; extensive modifications or repair; or capacity specified as being in a mothballed state. This does not include derated portions of Generating Capacity.

(2) Inoperable capacity should be reported in reliability assessments, but should not be considered in the calculation of capacity margins during the period in which the capacity is deemed Inoperable.
v) Deliverability

(1) Deliverability is defined as the ability of the transmission system to receive and deliver Generating Capacity from the generator to the electric load.

(2) Deliverable resources are reported in the reliability assessments for each reporting entity, and accounted for in margin calculations for such entities.

vi) De-rates on Peak

De-rates on Peak for the following types of Generation Capacity is the amount of existing capacity that is expected to be unavailable at the time of seasonal system peak load.

(1) Wind
(2) Solar
(3) Hydro
(4) Biomass
(5) Thermal

b) Categorization of Capacity

All existing and future (including conceptual) resources must be reported in one of the following categories. Resources may not be double counted across categories. It is up to the reporting entity as to which category resources are reported. Best judgment should be exercised in the determination of which category to report resources.

Resources that are contained within the region’s and/or subregion’s physical or electrical boundary must be reported by that region and/or subregion. Resources that are located outside of a certain reporting region’s and/or subregion’s physical footprint but are electrically connected only to that reporting region’s and/or subregion’s system should be reported by that region and/or subregion. The output of resources that cross boundaries to serve load should be reported as a purchase or sale.

I. EXISTING GENERATION RESOURCES

I.A. – Existing, Certain — Existing generation resources available to operate and deliver power within or into the region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

- Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
- Where organized markets exist, designated market resource\(^\text{12}\) that is eligible to bid into a market or has been designated as a firm network resource.

\(^{12}\) Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
• Network Resource\textsuperscript{13}, as that term is used for FERC pro forma or other regulatory approved tariffs.
• Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed\textsuperscript{14}
• Capacity resources that can not be sold elsewhere
• Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed\textsuperscript{15} during the period of analysis in the assessment

I.B. – Existing, Other — Existing generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in I.A. This category includes, but is not limited to the following:
• A resource with non-firm or other similar transmission arrangements
• Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason
• Mothballed generation (that may be returned to service for the period of the assessment)
• Portions of variable generation not counted in the I.A. category (e.g. wind, solar, etc. that may not be available or de-rated during the assessment period)
• Hydro generation not counted as I.A. or de-rated
• Generation resources constrained for other reasons

I.C. – Existing, but Inoperable — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero (0). This includes all existing generation not included in categories I.A. or I.B., but is not limited to, the following:
• Mothballed generation (that can not be returned to service for the period of the assessment)
• Other existing but out-of-service generation (that can not be returned to service for the period of the assessment)
• This category does not include behind-the-meter generation or non-connected emergency generators.

\textsuperscript{13} Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\textsuperscript{14} Energy only resources with transmission service constraints are to be considered in category I.B

\textsuperscript{15} Energy only resources with transmission service constraints are to be considered in category I.B
• This category does not include partially dismantled units that are not
forecasted to return to service

All existing generation resources must be counted in I.A., I.B. or I.C. and
should not be double counted between these three categories. Where
categorization as to the I.A. or I.B. category is not clear, the generation
should be designated as I.B.

II. – FUTURE GENERATION RESOURCES

This category includes generation resources the reporting entity has a reasonable
expectation of coming online during the period of the assessment. As such, to qualify in
either of the Future categories, the resource must have achieved one or more of these
milestones:

• Construction has started
• Regulatory permits being approved, any one of the following:
  o Site permit
  o Construction permit
  o Environmental permit
• Regulatory approval has been received to be in the rate base
• Approved power purchase agreement.
• Approved and/or designated as a resource by a market operator

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

• Contracted (or firm) or other similar resource
• Where organized markets exist, designated market resource\textsuperscript{16} that is
  eligible to bid into a market or has been designated as a firm network
  resource.
• Network Resource\textsuperscript{17}, as that term is used for FERC pro forma or other
  regulatory approved tariffs.
• Energy-only resources confirmed able to serve load during the period of
  analysis in the assessment and will not be curtailed\textsuperscript{18}
• Where applicable, included in an integrated resource plan under a
  regulatory environment that mandates resource adequacy requirements
  and the obligation to serve

II.B. – Future, Other – this category includes future generating resources that do not
qualify in II.A. and are not included in the Conceptual category. This category includes,

\textsuperscript{16}Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but
rather must be subtracted from the appropriate category in the demand section.

\textsuperscript{17}Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but
rather must be subtracted from the appropriate category in the demand section.

\textsuperscript{18}Energy only resources with transmission service constraints are to be considered in category I.B
but is not limited to, generation resources during the period of analysis in the assessment that may:

- Be curtailed or interrupted at any time for any reason
- Energy-only resources that may not be able to serve load during the period of analysis in the assessment
- Variable generation not counted in the II.A. category or may not be available or is de-rated during the assessment period
- Hydro generation not counted in category II.A. or de-rated

III. – CONCEPTUAL GENERATION RESOURCES

**Conceptual** — This category includes generation resources that are not in a prior listed category, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- “Place-holder” generation for use in modeling.

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

IV. – COMPUTATION OF CAPACITY MARGINS

The foregoing Categories of Capacity provide a comprehensive list for reporting the various types of existing, future, or conceptual generating capacities. The following provides guidance on how these categories are used to compute regional and sub-regional capacity margins for reliability assessment purposes.

**Existing, Certain** – These resources are confirmed able to serve load during the period of the analysis in the assessments. One hundred percent (100%) of these resources are included in the “Most Probable Resources” calculation.

**Existing, Other** – These resources may or may not be able to serve load during the period of the analysis in the assessments. Each reporting region or sub-region should make a reasonable judgment of the ability of such resources to serve load. In addition, the regions or sub-regions may adjust the capacity in this category, using a confidence factor, to reflect uncertainties associated with being able to rely on such resources to serve load. The adjusted capacity is included in the “Most Probable Resources” calculation.

**Existing, but Inoperable** – These resources are not able to serve load during the period of analysis in the assessments. These resources will be included in the Total Potential Resources capacity; however, such resources are not included in the “Most Probable Capacity Margin”.
**Future, Planned** – These resources are confirmed able to serve load during the period of the analysis in the assessments. One hundred percent (100%) of these resources are included in the “Most Probable Resources” calculation.

**Future, Other** – These resources may or may not be able to serve load during the period of the analysis in the assessments. Each reporting region or sub-region should make a reasonable judgment of the ability of such resources to serve load. In addition, the regions or sub-regions may adjust the capacity in this category, using a confidence factor, to reflect uncertainties associated with being able to rely on such resources to serve load. The adjusted capacity is included in the “Most Probable Resources” calculation.

**Conceptual** – These resources may or may not be able to serve load during the period of analysis in the assessments. Conceptual resources may be used by the NERC Regions in future years for planning purposes and for meeting local regulatory requirements. Resources in this category may be adjusted to reflect uncertainties associated with being able to rely on such resources to serve load. The adjusted capacity is included in the “Most Probable Resources” calculation.

The following charts shows how the foregoing Categories of Capacity are used to calculate capacity margins shown in the reliability assessments.

**Chart 2: Proposed Capacity Margin Categories/Plots**

* “Most Probable Resources” includes 100% of Existing-Certain and Future-Planned Resources and the confidence adjusted Existing-Other, Future-Other, and Conceptual Resources.

** Total Potential Resources includes 100% of all non-adjusted categories of capacity.
c) Retired Capacity

i) Retired Capacity is defined as Generating Capacity that is projected to be permanently removed from an operational state.

ii) Retired Capacity should be reported in the reliability assessments for each reporting entity. Retired Capacity is not accounted for in margin calculations.

Purchases and Sales

a) Contracts for Capacity

Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to purchased capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to sold capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one region and sold to another region, the region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside region. The purchasing region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

The following examples are provided to show how transactions are handled between two reporting regions for Purchases and Sales:

1. Unit physically located in Area A that is fully owned by a company in Area B and not connected to the Area A network but instead has a direct and adequate transmission connect to the Area A.

   Solution: Show the unit completely in Area B with no transfers. All derating accounted for in Region or Province B.

2. Unit physically located in Area A that is half owned by a company in Area B.

   Solution: Show the unit completely in Area A with a sale to Area B of half of the capacity. Area B would show a purchase of half of the capacity from Area A, as long as Area B can demonstrate adequate transmission capacity. Identify the sale/purchase as unit specific. Derating accounted for in Area A and sale reduced by 50% (depends on contract) amount.

3. Unit physically located in Area A that is fully owned by a company in Area B.

   Solution: Show the unit completely in Area A with a sale to Area B of the full amount. Area B would show a purchase of the full amount of capacity from Area A, as long as Area B can demonstrate adequate transmission capacity. Identify the sale/purchase as unit specific. The derating due to transmission should be accounted for in Area A and the sale reduced by derated amount in Area B.

The following are categories of Purchases and Sales contracts:
ii) Firm

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

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

iii) Non-Firm

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

(2) Non-Firm Purchases and Sales should not be reported in the reliability assessments.

iv) Expected

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

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

v) Provisional

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

(2) Provisional Purchases and Sales should be considered in the reliability assessments.
Resource Assessment

A recent survey of Resource Adequacy Assessment practices conducted by NERC’s Resources Issues Subcommittee (RIS) provides insights into common practices and objectives of resource adequacy assessments as well as regional differences. Approximately 60% of the survey recipients responded including all eight of NERC’s regional entities, 57% of NERC’s planning coordinators and three entities that are not NERC-registered Planning Coordinators. Reference is also made to documents, which explain the resource adequacy assessment methods of ISO New England (ISO-NE), ERCOT, the Midwest Planning Reserve Sharing Group (Midwest PRSG) and the Northwest Power and Conservation Council (NWPCC).

In reviewing the survey responses, there is sufficient commonality in certain elements of resource adequacy assessments that these could be viewed as expectations:

- **Assessment against specified Level of Reliability:** Resource adequacy assessments are intended to assure sufficient supply-side and demand-side resources to meet the aggregate electrical demand and energy requirements (including losses) of the end-use customers with a specified degree of reliability.
  
  - That specified level of reliability is typically expressed as the “loss of load expectation” (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year” 19
  
  - Although resource adequacy requirements are almost always expressed in terms of planning reserve margins, or capacity margins (for the sake of simplicity, these will collectively be referred to as reserve margins); the numerical targets are typically derived from some type of probabilistic assessment. Even where a deterministic analysis is the basis for reserve margin targets, an effort is made to assess the various factors that pose a risk to the adequacy of resources comprising the bulk power system and provide coverage for these risks through reserve margin components.

- **Assessment is over Long-term Timeframe:** The timeframe of the assessments is generally from 1 or 2 to 10 years out to allow for timely notice of any impending generation insufficiencies to the targeted audience of the assessment, i.e. the market or utilities’ state regulators, in order to allow sufficient time to implement resource adequacy measures to avoid such insufficiencies.

Tables ____ & ____ provide a summary of the results of the Resource Adequacy Assessment Practices survey conducted by the RIS in 2008.

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19 NPCC Resource Adequacy Design Criteria
# TABLE ___

<table>
<thead>
<tr>
<th>Regional Entity/Planning Coordinators</th>
<th>Model Description</th>
<th>Resource Adequacy Measure</th>
<th>Stochastic Parameters</th>
<th>Planning Horizon</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>Name of Model</td>
<td>Prob/ Deter</td>
<td>Time Step</td>
<td>Probabilistic Metric/Target</td>
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<tr>
<td>ERCOT (^1)</td>
<td>ProSym</td>
<td>Prob</td>
<td>Hourly</td>
<td>Hourly LOLP ≤ 1 event in 10 years (^2)</td>
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<td>FRCC</td>
<td>TIGER</td>
<td>Prob</td>
<td>Hourly</td>
<td>Peak day LOLP ≤ 0.1 days/year</td>
</tr>
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<td>MRO</td>
<td>GE MARS</td>
<td>Prob</td>
<td>Hourly</td>
<td>No study yet; LOLE standard 15% (EUE) (Manitoba)</td>
</tr>
<tr>
<td>MARELI</td>
<td>PROM IV</td>
<td>Prob</td>
<td>Hourly</td>
<td></td>
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<tr>
<td>RFC</td>
<td>Various</td>
<td>Prob</td>
<td>Hourly</td>
<td>LOLE ≤ 1 occurrence in 10 years 18%</td>
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<tr>
<td>RFC</td>
<td>GE MARS</td>
<td>Prob</td>
<td>Hourly</td>
<td>In progress; 1999 Study LOLE of .1 12% cap mrg: 9% if hydro 75%</td>
</tr>
<tr>
<td>RELY</td>
<td>GE MARS</td>
<td>Prob</td>
<td>Hourly</td>
<td>In progress; 1999 Study LOLE of .1 12% cap mrg: 9% if hydro 75%</td>
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<tr>
<td>WECC</td>
<td>SAM</td>
<td>Deter</td>
<td>Seasonal peak hour</td>
<td>No probabilistic building block: 12% - 17%</td>
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</tbody>
</table>

\(^1\) Both ERCOT and SPP are Regional Entities and the only Planning Coordinators for their areas

\(^2\) Global Energy Decisions was the contractor to perform the LOLP studies
a) **Resource Adequacy Analysis**

The survey results indicate that six of the eight regional entities and the vast majority of the planning coordinators use some type of probabilistic assessment method to perform their resource adequacy analyses. SERC, a region currently without a resource adequacy assessment method, has formed a reliability assessment subcommittee, which may eventually perform a regional assessment.
WECC, a region currently using a deterministic resource adequacy assessment method, has initiated a pilot project to determine if a probabilistic assessment is workable for that region.

These probabilistic analyses generally fall into two categories: Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE). Regional differences in resource mixes (abundance of energy-limited resources or more or less well-developed demand response programs), the geographical location of resources on the transmission grid, access to out-of-area reliability resources (i.e. tie benefits) and/or market or regulatory approaches to implementing resource adequacy may all affect the assessment methods and assumptions. Following is an overview of the differences and similarities in resources adequacy analysis methods:

i) PROBABILISTIC METHODS:

The transparency of these assessments is somewhat impeded because of the lack of uniformity in assessment metric definitions. However, in almost all cases, the objective is to test whether existing and future resources are sufficient to assure an LOLE of no more than 1 day in 10 years where all relevant factors and uncertainties are included in the simulation. Therefore, despite the differences in definitions and methods, the goal is that the resulting levels of adequacy be similar.

1. **Stochastic Parameters:** The model used to assess resource adequacy should take into account all relevant factors and uncertainties and include them in the simulation. Practically speaking this can be done by representing certain parameters, which embody much of the “risk” that there may be insufficient resources to meet load, as stochastic parameters. This means that there needs to be information regarding the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, or as distribution of discrete samplings such as a number of years of historical resource availability (e.g. wind production or hydro production and/or reservoir information) or discrete histories on the forced outage attributes of thermal generation.

The RIS survey indicated that, in all cases, forced outages of thermal generators is one of the stochastic parameters in probabilistic assessments. In almost all cases, load uncertainty, i.e. load uncertainty due to adverse temperatures, is another stochastic parameter. In FRCC, which does not include load uncertainty as a stochastic parameter, load uncertainty is modeled using scenario analyses. If load uncertainty due to load growth uncertainty is modeled, it is generally analyzed using scenario analyses. In areas, with an abundance of wind or hydro resources (especially if the resource is storage-limited), wind and/or hydro generation may also be
modeled as stochastic parameters in which a key determinant of reliability is the ability of other resources to support the reliability index during periods of low availability of intermittent resources.

2. **Probabilistic Methods**: There are two primary methods to model uncertainty in the probabilistic simulation tools whereby two probability distributions are “added” or “subtracted” to or from each other to get a combined risk distribution. Convolution is the mathematical technique whereby selected probability distributions are combined. In resource adequacy assessments, a probability distribution of the availability of generation capacity is combined with a probability distribution of customer loads to quantify how often loads would exceed available resources.

   a. **MONTE CARLO CONVOLUTION**: The first method is convolution through Monte Carlo, or random picks, from probability distributions. The result of this type of convolution is a series of discrete, identifiable events when loads exceed available generation. The frequency of these occurrences is converted into a resultant distribution which can be converted to a probabilistic reliability metric.

   b. **ANALYTIC CONVOLUTION**: The second method is through analytic convolution, which means that all of the probability distributions of load are expressed in the form of mathematical equations and mathematically combined. The result of this type of convolution is a modified mathematical, represented, distribution which can be converted to a probabilistic reliability metric. Because of the complexities of the mathematics, many of the constraints in a large integrated power system cannot be explicitly included in the models.

3. **Definition of a Loss of Load (LOL) Occurrence**: There are a number of definitions regarding what constitutes a Loss of Load Occurrence in a probabilistic assessment.

   a. **INABILITY TO MEET FIRM LOAD**: Using this definition of a LOL occurrence, the region, or subregion, would use all available capacity including operating reserves to serve firm load. If in any hour, or whatever time frame constitutes an “LOL occurrence”, load exceeds available capacity, then this is defined as an “LOL occurrence.” Based on feedback solicited subsequent to the RIS survey, it appears almost all regions use this definition of an LOL occurrence.

   b. **INABILITY TO MEET FIRM LOAD PLUS OPERATING RESERVES, OR A PORTION THEREOF**: Using this definition of an LOL occurrence the region, or subregion, would use all available
capacity to meet firm load and operating reserves, or perhaps just the spinning component of operating reserves. An “LOL occurrence” would be defined as the inability to meet load plus operating reserves, or a component thereof. ERCOT uses this definition of an LOL occurrence.

c. **INABILITY TO MEET FIRM LOAD PLUS OPERATING RESERVES ABOVE A CERTAIN THRESHOLD**: The Pacific Northwest (PNW) subarea of WECC only counts LOL occurrence as an energy or capacity curtailment that exceeds a minimum threshold. The reason for setting a deterministic threshold in the analysis is to compensate for some minimum amount of operational flexibility that cannot be, or is not, represented in the reliability modeling to assure that the model calculated customer curtailment is a true LOL occurrence. Since the model is unable to simulate the full flexibility of the hydro system, which supplies 75% of the subarea’s load in a normal water year, to deal with thermal generator outages, cold snap or heat wave events; planners have determined a reasonable minimum threshold level above which a curtailment is considered a “LOL occurrence”. An energy “LOL occurrence” is defined as the inability to meet firm energy load over a season, or over a year. A capacity “LOL occurrence” is defined as the inability to meet firm load plus operating reserves in a single hour.

4. **Probabilistic Metrics**:
   
   a. **LOLP**: Loss of Load Probability [LOLP] is the building block of probabilistic analyses. LOLP is typically defined as the probability of firm load demand not being met in any given time period. In some areas, the determination is whether firm load demand plus operating reserves, or a portion thereof, can be met in a given time period. When the probabilities of events are summed over time, the result is an expectation.

   b. **LOLE**: Loss of Load Expectation is defined as the sum of LOLP values over time. For example, if a system was always short of capacity, in every hour in a year, with no chance of having enough capacity, the LOLE would be 8760 Loss of Load Hours per year or 365 Loss of Load Days per year, or 260 Loss of Load Weekdays per year.

   For a Monte Carlo based LOLE evaluation, many simulations are required for probabilistic assessments to develop a statistically significant reliability index. Thus, a system that exactly satisfies the

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20 NPCC including NYISO, ISO-NE, etc. This is also the PJM definition, which includes the Midwest PRSG.
21 ERCOT
metric of an LOLE of 1 day in 10 years might be a system that experiences misses in 100 days out of a 1000 simulation years in a 10-year horizon (100 days per 1000 simulated years or 0.1 days per simulated year). For quantifying reliability and determining the required reserves necessary to meet the 1 day in 10 years LOLE, many planning authorities use a reliability model. For example, a typical model compares the available capacity resources against loads using statistical techniques and determines the annual LOLE. The LOLE is calculated for every period of the year and accumulated through the year. Some of the periods used in this analysis include peak hour for 260 days, i.e. all days per year excluding weekends, peak hour for 365 days, or even every hour of the year. When the LOLE for all of the periods have been determined and summed for the year, the system is considered to be in compliance with the annual resource planning reliability criterion if the cumulative LOLE is lower than, or equal to, 1 day in 10 years on an annual basis (or 0.1 days per year). In ERCOT, LOLE stands for a loss of load event and is described as any single hour or group of consecutive hours where load exceeds available resources. For example, 1 hour alone of unserved energy constitutes a LOLE just as 5 consecutive hours of unserved energy constitutes an LOLE. Results are given as average Loss of Load Events in ten years.

Finally, in the PNW, LOLE is defined as the probability of a certain energy load not being met over a certain timeframe. In the case of this area, the LOLE target is 5%

c. **LOLH**: Loss of Load Hours is the hourly counterpart to the daily LOLE calculation but the calculation is based on the summation of the probabilities for all hours in a year.

d. **EUE**: Expected Unserved Energy [EUE] is typically synonymous with Energy Not Served [ENS], measured in MWh, across all iterations of the stochastic simulation. Results are given as average MWh of EUE in ten years. The EUE index is similar to the LOLH index except that the MW shortage in each period is weighted by the probability.

5. **Impact of Size of Footprint on LOLE and Reserve Margin Analysis:**

The LOLE analysis is influenced by the size of the area over which the analysis is performed. The larger the system, the lower the reserve margin needed to achieve an LOLE of 0.1 day per year because of factors such as

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22 The NWPCC defines LOLP as the probability that an energy “miss” will occur over the winter season, or over the year.

23 ERCOT
load diversity and the availability of additional generation to meet low probability contingencies. Interconnected areas will have a lower LOLE than that of an individual area, which is not interconnected with another area.

One of the key assumptions in the LOLE calculation is that transmission is infinite to move capacity and energy from where it is located to where it is needed. Certain models can take into consideration some amount of transmission limitation. However, as system size becomes larger, the validity of this assumption begins to become more questionable. Transmission interfaces are typically influenced by the state of the system and the interface limits are most often developed based on the worst contingency with all lines in service. The validity of the all lines in service assumption, and the implications for large footprint reliability studies is a topic of future RIS effort. (Could use historical ATCs on Interfaces as a potential methodology to determine what future capabilities are. It may not be ideal, but it does give some sort of variation and not assuming that whatever is needed can be purchased from the interface.)

ii) DETERMINISTIC APPROACHES & METRICS:

The RIS survey indicates that only one Region, WECC, uses deterministic methods to develop resource adequacy targets. WECC uses a “building block” approach to cover operating reserves, additional reserves needed to cover prolonged forced outages as well as reserves needed to cover severe weather contingencies. WECC’s planning reserve margins are specified by subarea for both summer and winter.

Two of the sub-areas within WECC have specified resource adequacy targets, California and the Pacific Northwest (PNW). The WECC targets are not significantly different for California. However, the PNW targets of 23 and 24% [capacity margin or reserve margin], in winter and summer, respectively, over an 18 hour sustained peaking period (6 highest load hours over 3 consecutive days), which are derived from an LOLP analysis, are considerably higher than the WECC targets.

b) Modeling of Demand in Adequacy Assessments (i.e. hourly, weekly, etc.)

On the one hand, appropriate load representation for resource adequacy analysis can be quite simple, but needs to be sufficiently detailed to permit the analysis to cover all of the relevant risk factors. On the other hand, load representation also needs to be kept down to reasonable levels to permit solving the analysis in a reasonable time.

It is important to model load uncertainty. As discussed above, weather-related load uncertainty is generally done by depicting load as a stochastic parameter in the probabilistic analysis. Economic-related load uncertainty can be modeled
using scenario analyses. Modeling of load correlations between transmission areas or across days due to a heat wave or cold snap is also usually more important than the modeling of the typical daily or weekly load shape.

i) SINGLE TRANSMISSION AREA ISSUES

Load representation must be sufficiently detailed to capture all times and events which may cause loss of load. The representation of load variation due to weather, economic conditions and other factors is the most important factor in resource adequacy analysis. Load shape factors only become significant after weather or economic conditions have driven demand (relative to supply) up to levels with a high risk of loss of load.

In thermal systems or those with little energy-limited generation, each day may be considered independent. For the most part, equivalently increasing the number of trials performed [Note: In any probabilistic analysis every day is another sample AND another risk that will contribute something to the index. It is not another Monte Carlo replication]. Uncertainty can then be reduced to the distribution of daily peaks.

If (i) the risk of loss of load only occurs in contiguous hours around seasonal peak, (ii) there are no transmission limitations in the area and (iii) no resources are limited by such things as time of day, energy, or number of occurrences, a simple probabilistic distribution of seasonal peak may be sufficient. Traditional analytical convolution of this distribution with the distribution of available capacity is adequate for this analysis. Unfortunately few systems are this simple anymore.

For energy-limited systems, the sequence of load over a few days, a week, season or even multiple years may be significant because of the draw-down of energy stores such as hydro-based energy in reservoirs. A full representation of uncertainty may be impractical. No one technique has been shown to be the best in these situations.

Appropriate load shape for analysis (usually an 8760 hourly annual load shape) are typically selected for patterns of load across days than patterns of loads within days. The diurnal load cycle is usually well-defined and only in a few instances an important factor in resource adequacy. Appropriate modeling of heat or cold waves is a main consideration. Annual load cycles may be important if resource scheduled maintenance may interact with load to create loss-of-load events.

The load representation should be typical and not an average which has smoothed out all of the useful information. Some or all aspects of weather variation may be included as part of the design of the hourly load shape.
Using the hottest year on record does not necessarily provide the most conservative answer once it is input into the resource adequacy assessment model and adjusted to represent a future year. For example, if the peak loads in the “hot” historical year are much higher than the other days and this profile is used in a normal weather year, then all the non-peak days will be much lower than the forecast peak load and LOL occurrences will be concentrated on only the “hot” day.

The representation of hourly load and all of the various types of uncertainty must work together to represent the combined distribution of load. The combined load representation (as created in the model is best) should be checked to ensure it is appropriate. Missing uncertainties results in the obvious problem of planning for too few resources to achieve a reliable system. Double accounting of uncertainties results in a more reliable system, but at the cost of paying for additional, perhaps unneeded resources.

ii) MULTIPLE AREA ISSUES

If transmission limitations within the area impact resource adequacy or if support from other areas is to be considered in the analysis, we must at least implicitly model the load shape and uncertainty within multiple areas and the correlation of uncertainties and base characteristics between or among areas.

Each area has all of the issues described under single area issues. The correlation of all of the uncertainties and base load shapes across the areas must now be considered. How correlated is the weather across the areas? Is the total analysis region large enough that the movement of weather systems through it should be modeled?

The more detailed the load representation the more difficult this is to model. Often the best that can be done is to select the same hourly load pattern for all areas from one historic year determined to be the best representation of a typical year (not average and probably not extreme depending on the modeling of uncertainty). Because historical loads do not reflect the future year conditions exactly, they must be scaled. Whether the scaling is applied to all of the regions simultaneously or individually affects the amount of diversity incorporated in the load model.

Modeling all areas as peaking at the same time (day and hour) is conservative but may be the best alternative.

iii) LOAD UNCERTAINTY MODELING TECHNIQUES
As is the case for probabilistic methods, in general, load uncertainty modeling techniques may be classified into two general categories:

- Load uncertainty represented as a distribution
- Load uncertainty representing historical patterns with diversity embedded

These techniques would be applied to a “base case” and different scenarios.

The use of an analytical convolution is the best technique to use for load uncertainty that covers all possible events. Unfortunately, it becomes complicated when correlation of loads between areas or over time is considered. If all the information about weather related uncertainty is included in a load distribution for one area and all the weather related uncertainty is included in a load distribution for a second area, unless there is some correlation factor expressly included, the effects will be considered to be random and independent. (ie. one area could be experiencing an extreme heat wave while the other area is experiencing unseasonably cool weather.) It also requires a similar resource uncertainty representation. For very simple systems, it is fast and accurate, but it consumes large amounts of analyst resources and becomes too complex for multi-area systems. This technique is still appropriate under certain conditions.

For detailed multi-area simulations (with transmission constraints between areas or different emergency operating procedures), analyses using Monte Carlo simulations are generally performed today in resource adequacy evaluations. The issue here is computer solution time. A large number of trials are required because loss-of-load events have low probability. The issue isn’t the ability to model load uncertainty or correlations but the estimation of appropriate uncertainty distributions and correlation (in time or between transmission zones) which are then input into the analysis.

Scenario analysis may be used in conjunction with either technique above. Scenario analysis is often used to complement Monte Carlo analysis. It is good for representing rare or complex events especially those which can’t be easily parsed into distributions and correlations, or those which would require too many trials to make sure they were captured in Monte Carlo analysis. For loads specifically, scenario analysis is often useful for economic forecast uncertainty or to model the impact of a significant load shape changing event.

c) **Demand-Side Management (DSM) Resources**

DSM resources are particularly problematic when interpreting resource adequacy analyses. DSM can be modeled implicitly (as a modification to load) or explicitly (as a resource—whether an emergency resource, or as a dispatchable or non-dispatchable resource). If modeled as a resource, there are reserve margin
requirements; otherwise, if modeled as a load reduction, no reserve margin requirements are reflected even though the load reductions may not be 100 percent certain to materialize when activated and may not be able to provide 10 percent of the amount of load relief sought for every activation.

Another issue is that physical equipment associated with the DSM is seldom countable for analysis and is under distributed control for use, installation or retirement. In addition many DSM resources are not solely equipment based, but depend directly (rate response) or indirectly (industrial equipment is resource only if it is in production to meet a demand) on customer behavior. To further complicate analysis, some but not all DSM resources may be partially included in the reported existing load or into the load forecast. Also, what one area considers a DSM resource may be considered a firm load elsewhere. This complicates whether a LOL occurrence should be counted or not if the two areas were compared using the same criterion.

In spite of the problems, DSM resources are legitimate resources to be included in current and future resource evaluations. In many cases, DSM resources have very long ‘construction’ periods before they reach their full capacity value but, contrary to supply resources they start to provide benefits immediately. But because ‘construction’ of demand resources can also be terminated or even reversed easily and quickly, many analysts are often reluctant to include them in resource adequacy assessments. Finally, DSM resources, especially demand response may only be callable a limited number of times per season.

In the past, DSM resources in resource adequacy evaluations have usually been interruptible loads at a small number of large industries and amounted to only a few percent of total resources. Treatment was largely standardized as a reduction from total load to create firm load excluding the interruptible loads. Since the 1980’s, the number and type of DSM programs has been increasing. In the future DSM resources may add up to more than 10% of total resources. The type of program also has broadened into the residential and commercial sectors, and includes non equipment-based effects such as rate response.

One final issue with DSM resources is their impacts have naturally been included in the historical demand series. If these resources are to be modeled explicitly during the resource adequacy assessment, the load forecast (and presumably the base historical load series) must be adjusted (upward) to obtain load before demand-side resource implementation. If the load is not modified DSM resources are implicitly being assumed to be used at the same time and in the same pattern in the future as in the past and their impact may be modeled as growing at the same rate load growth. Ideally, DSM resources are only used when economic or necessary to avoid loss of load. Their use does not always occur at the same time year to year, it usually occurs when load is highest but may be used at other times,
and its impact will depend on time of use. The RIS survey responses did not shed provide much insight into a typical treatment of DSM resources.

Table 1 below summarizes a number of ways to include DSM resources in resource adequacy evaluations -- each with an explanation of the advantages and disadvantages. It is appropriate to use more than one method of modeling DSM resources within the same analysis. Within one analysis, conservation programs may be intrinsic to the load forecast; the impact of residential time-of-use rates may be used to explicitly alter load; interruptible customers may be treated as an emergency operation procedure; air conditioner cycling may be explicitly modeled on an hourly basis; and public appeals may be ignored as their use is considered a loss of firm load.
Table 1  
Reporting of DSM Resources in Reserve or Capacity Margin

<table>
<thead>
<tr>
<th>Treatment</th>
<th>Examples</th>
<th>Implications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Firm Load</td>
<td>Voltage reductions or public appeals not considered in resource adequacy analysis.</td>
<td>Load must be adjusted by adding back in the affects of these actions.</td>
</tr>
<tr>
<td>Load Forecast Modification - Implicit</td>
<td>DSM resources dispatched locally (by customer or distribution utility). Allow DSM resources to remain in historic load series and do not model in load forecasting.</td>
<td>Firm load is understated. Affects of demand resource use should be added back in. Information required for adjusting load is often not available.</td>
</tr>
<tr>
<td>Load Forecast Modification - Explicit</td>
<td>Any DSM resource may be modeled this way. Often the best treatment for non-dispatchable demand resources.</td>
<td>Parameters necessary for adjusting load are readily available. In margin ratios, DSM resources may be used to reduce reported firm load or added to resources. No standard treatment is currently defined. Usually use derated or effective capacity of demand resource.</td>
</tr>
<tr>
<td>Resource - EOP</td>
<td>Voltage reductions, public appeals and interruptible load often modeled as emergency operating procedures (EOP).</td>
<td>EOPs are often not included either as a load reduction or as a resource in margin calculations. This makes comparison of margins between jurisdictions difficult.</td>
</tr>
<tr>
<td>Dispatchable Resource</td>
<td>Dispatchable (often industrial) load.</td>
<td>In margin ratios, demand resources may be used to reduce reported firm load or added to resources. No standard treatment is currently defined. Either installed capacity or effective capacity may be used in ratios hampering comparison across areas.</td>
</tr>
<tr>
<td>Dispatchable Resource with Limitations</td>
<td>Interruptible load may have a maximum number of times it may be called upon in a period of time. Permits modeling of such things as loss of diversity from air conditioning control.</td>
<td>Usually but not always coincides with including demand resource on resource side of ratio. Characteristics related to usage limitations are cannot be reported in simple reserve or capacity margin ratios. Calculation of effective capacity is not always obvious—for example effective capacity of air.</td>
</tr>
</tbody>
</table>

d) Supply Fuel-limited (hydro, wind, etc.)

State policies such as Renewable Portfolio Standards (RPS) and those favoring a carbon-constrained future are big drivers to the construction of renewables, some of which are highly variable and not dispatchable (e.g. wind and solar PV). Hydro is a traditional fuel-constrained technology. Finally, some thermals are becoming energy-constrained due to air quality and other environmental limitations.

The traditional approach in a capacity adequacy assessment has been to derate energy-limited resources. However, this approach does not fully capture that
some resources such as wind are considerably more constrained than other resources such as hydro. One method to derate wind is to consider its firm load carrying capability. Another approach has been to evaluate wind’s contribution to capacity adequacy when it is needed most, i.e. during cold snap or heat wave events. The motivation for derating resources is to view them in a more comparable manner with other more traditional resources so the familiar comparative metrics such as precent reserve margins / percent capacity margins remain meaningful. For example, if wind were included without derating capacity (as are virtually all other resources) then minimum reserve margins of 90 percent could be reasonable for large penetrations. In such a situation the addition of more wind resources would, most likely, simply increase the minimum reserve margin, with only minor improvements in avoiding additional LOL occurrences.

Still another approach is to model wind, hydro and other energy-constraint resources as stochastic parameters. This approach certainly identifies the attributes of energy-constrained resources better than the derating approach discussed above. However, it is important to keep in tact partial correlations. For example, load and wind may be unrelated except that during periods of severe heat or cold, wind may be partially correlated in a negative manner to load.

e) Addressing Resource Deliverability

Resource deliverability can have different meanings as defined by NERC. The recent RIS survey also gathered information about how regional entities and planning coordinators define the term “deliverability”. Based on the results of the survey, approximately 90% of the entities that responded do not have an official definition of “deliverability” with regards to generation resources.

The survey also requested the entities to explain what is done to ensure that the generation resources are deliverable to meet the load requirements at the time of system peak. The responses varied significantly from entity to entity. However, approximately 97% of the entities who responded perform some type of transmission assessment including regional studies, transmission provider studies and interconnection study processes governed by each transmission provider’s OATT. The following table is a summary of the results of the survey:

<table>
<thead>
<tr>
<th>RESOURCE DELIVERABILITY</th>
<th>Description of Test</th>
<th>Response (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Interconnection process—all resources are deliverable</td>
<td>39</td>
</tr>
<tr>
<td></td>
<td>Transmission provider studies</td>
<td>29</td>
</tr>
<tr>
<td></td>
<td>Regional transmission studies</td>
<td>29</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>3</td>
</tr>
</tbody>
</table>
RESOURCES DELIVERABILITY REPORTING GUIDELINES

The Reliability Assessment should describe how generating resources are determined to be deliverable or have sufficient transmission capability to serve the load under forecasted peak demand conditions. For example, some entities may perform a generator deliverability test as well as a load deliverability test. In order to ensure consistency throughout the Reliability Assessment document, the following guidelines are recommended when developing the self-assessment narratives:

- Describe conditions under which transmission studies are performed to ensure resource deliverability (e.g., load conditions, resource maintenance, transmission maintenance, contingency events evaluated, power transfer conditions, worst case dispatch, etc).
- Describe the interconnection process as it relates to a specific resource and transmission capability. For example, describe the transmission studies performed, if any, as part of the interconnection process using the guideline provided above. If this process is governed by the transmission provider’s Open Access Transmission Tariff, then briefly describe the process and elaborate on the deliverability portion if appropriate.
- For network resources explain how a resource attains this status. For example, explain how “network resource” status is determined (e.g., transmission studies, ATC, transmission rights, etc). If transmission rights can be purchased, then explain how are these transmission rights determined to be available and under what conditions (refer to the first bullet).

f) Capacity/Reserve Margin Analysis

The following discussion regarding reserve margin analysis is largely extracted from an ERCOT resource adequacy assessment document.

A number of questions arise when the objective is calculating an accurate planning reserve margin for a system. The common method of calculating planning reserve margin is represented by the following equation:

\[
\frac{[(\text{Resources} + \text{Purchases}) - (\text{Peak Load} + \text{Sales})]}{(\text{Peak Load} + \text{Sales})}
\]

The capacity reserve margin calculation is similar except that the denominator is installed capacity, or resources plus purchases.

An important issue in preparing reserve margin analyses is how to count resources and how to depict load. How much of wind capacity should be counted in the calculation? How are mothballed units counted in the calculation of reserve
margin? What is considered the peak load hour? How are imports (market), or tie benefits counted? Following are typical ways of treating loads and resources:

**Peak Load:** Peak load is generally the 50/50 (expected peak) of the control area. In this study, where ERCOT is modeled as a single zone, the 50/50 peak for the entire system occurs in August.

**Resources:** The maximum capacities (nameplate) of thermal and hydro stations that are in ERCOT are included in the calculation. In other analyses, hydro capacity is typically derated to that available under adverse or critical water conditions. [Could use Monte Carlo along with historical hydro energies] In ERCOT, wind capacity is counted at 8.7 percent based on the effective load carrying capability (ELCC) of wind capacity analysis. NWPCC is currently counting wind at 5% of its installed capacity. Other analyses base wind’s contribution to capacity adequacy at that available historically. At ERCOT, interruptible loads and demand-side management programs are included as resources. Often interruptible loads are included as one of the Emergency Operating Procedures, which is counted in resource adequacy assessments. In ERCOT, approximately 5,500 MW of mothballed units that are not expected to come back on-line before August 2008 have been omitted from the reserve margin calculation.

**Imports and Purchases:** In this study, only known power purchase agreements with outside markets were considered in the calculation of the reserve margin. Import capability was not counted as additional capacity. Other studies do include tie benefits in the reserve margin calculation.
Transmission Reliability Assessment

Perfect or even near perfect transmission reliability would cost an infinite amount of money. Imagine a remote customer that needs to be served 100 percent of the time. In other words, zero risk of loss of supply to this customer. Obviously, this would require building a transmission line to serve the load. This single line would obviously not be enough, no matter how solidly it was built, to ensure the customer is served 100 percent of the time. For example, what if that line is struck by lightning? The customer would not have service. Therefore, two transmission lines need to be built, at least doubling the cost. Having a second transmission line will not be sufficient either because what if one line is out on maintenance and the other is struck by lightning. Two transmission lines would not be enough and a third line would be needed tripling the cost, and so on. Even if we had 100 transmission lines serving a load, there is still a very small possibility (earthquake, hurricane) that all those lines could be taken out of service. The planner must make a decision on how many lines are enough. In other words, how much risk is acceptable versus the cost necessary to serve the demand to some industry accepted level of reliability. Of course the bulk electric power system is much more complicated than trying to serve one customer.

a) Overall Transmission Assessment statement
b) Transmission additions and backbone project description
c) Transfer capability results
d) Thermal Issues (Rating violations and mitigation plans, etc.)
e) Voltage Issues
   i) Transient Voltage dip
   ii) Dynamic Reactive Requirements
   iii) Under Voltage Load Shedding
   iv) Stability
f) Dynamic Stability Issues
   i) Transient Stability
   ii) Long-Term Stability (e.g., beyond 20 seconds after a transient event)
   iii) Small Signal Stability
g) Under Frequency Load Shedding
h) Short Circuit Levels
i) Describe the results of the TPL studies
Operational Issues

a) Environmental, regulatory or other restrictions

b) Major unit or facility (e.g. PAR) outages that affect operation of the bulk-power system, and/or temporary operating measures to mitigate concerns

c) Other issues, or operating conditions (e.g. higher than expected forced outage rate of units, etc.) and any mitigation procedures
Other Issues (Examples)

a) New or emerging issues, if any
b) Define or give examples of what is a significant issue
c) Special reliability assessments performed
d) Examples:
   i) Aging Infrastructure
   ii) Drought/Flood Conditions
   iii) Equipment/construction/siting delays
   iv) Other issues of concern
Scenario Assessment

Background

Each year, NERC’s staff and its technical committees prepare a 10-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 LTRA cycle, NERC will begin development of plans to address scenarios identified in the 2007 LTRA. The plans developed to address the scenarios will be studied during 2008, and the results will then be reported by the regions for comparative purposes in 2009 LTRA. In the summer of 2008, the Planning Committee will be 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 LTRA will include not only the reference case, but also specific scenario analysis if a scenario is chosen by the PC. Figure below 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
- Weather uncertainty evaluation
- Gas deliverability and supply
- Capacity planning indicators that are separate from energy planning indicators
- 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 as supporting documentation for regional and long-term reliability assessments when they become available. Figure 7 shows the recommended flowchart for this process (as approved by the PC in December 2007).

![Flowchart of Scenario Analysis Process](image)

**Figure 7: 2008 Emerging Issues and Scenario Analysis**

**Template for Submittal**

For consistent submittal, a template for scenario submittal was developed by the Reliability Assessment Subcommittee. The risk assessment process the PC will follow was also outlined in this template, and shown below.

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24 This activity has been taken up by the (Demand-Side Management Task Force), under the direction of the Resource Issues Subcommittee.

25 Confidential Information will be handled by NERC staff, following Section 1500 of NERC's Rules 7 Procedures (ftp://www.nerc.com/pub/sys/all_updl/rop/NERCRulesofProcedure-Complete.pdf)
Emerging Issue Template
Background, Qualification and Submittal

Background

Each year, the 10-year *Long-Term Reliability Assessment* (LTRA) forms a basis for the NERC reference case. The reference case is generally based on the assumption that policy/regulations will be constant throughout the studied timeframe and a variety of economic trends, weather patterns and system equipment behaves as expected, usually based on historic performance trends.

Emerging issue analysis supports the development of scenarios, analysis of which can indicate the sensitivity of the reference case to changes in pre-specified conditions and provide insight into risks to regional reliability. Development of a small set of scenarios for comparison to the reference case is a valuable way to better understand the robustness of the reference case and to study potential impacts of scenarios on reliability.

In support of this effort, NERC’s Planning Committee (PC) has charged the Transmission Issues, Resource Issues and Reliability Assessment Subcommittees each to submit 3 to 5 high priority plausible emerging issues that could impact the bulk power system reliability over the next 10 years.

The PC will then prioritize the resulting emerging issues using a risk assessment matrix (Attachment I) and, based on the results and PC member judgments, they may select potential scenario(s) for study in the future. For each emerging issue, it is important to understand the impact on bulk power system reliability and influence on planning, operations and resources plans.

Emerging Issue Qualification

To qualify for consideration in this process, candidate emerging issues must meet the following criteria:

- Subcommittees should have a high degree of confidence that the emerging issue to be evaluated would affect the reliability of the bulk power system for more than a single year in the LTRA time period (10 year assessment window)
- The effects of the emerging issue on reliability are projected to be seen in the region no sooner than 3 years out, to allow sufficient time for analysis
- The effects of the emerging issue should represent a potentially significant impact to the bulk power system reliability across at least a regional footprint, and should not be a local/subregional reliability issue more effectively assessed by the affected Transmission Planners/Planning Authorities.

Template for Emerging Issue Submittal
For each candidate emerging issues, submitted provide:

**Emerging Issue #X: Title of Emerging Issue here.**

<table>
<thead>
<tr>
<th>Emerging Issue</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizon</td>
<td>Number of years</td>
<td></td>
</tr>
<tr>
<td>Background</td>
<td>What is the change from the reference case?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>What changes during the 10-year horizon?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>What is the impact to regional reliability?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Resource Adequacy Considerations [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Transmission Adequacy Considerations [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Resource Siting Impacts [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Operations Impacts [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Describe assumptions</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Provide guidance on future studies</td>
<td></td>
</tr>
</tbody>
</table>

The information in this table should be of sufficient detail to allow the PC to conduct its risk assessment & ranking exercise. The optional Potential Study Scenarios section, if completed, can assist the RAS in understanding how the emerging issue could impact bulk system reliability. Additional information will be collected by RAS for those emerging issues that are selected and approved by the PC for consideration in the LTRA assessment cycle.

An example Emerging Issue submittal can be found in Attachment II.

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26 If “Yes” explain how this item could be affected
Reliability Impact Ranking:

The following question IS DESIGNED TO GATHER information on your view of each of the emerging issues below along with your RANKING of the LIKELIHOOD and how SEVERE the impact would be on bulk power system reliability.

**INDIVIDUAL RESPONSES WILL BE KEPT CONFIDENTIAL.**

What do you believe is the LIKELIHOOD of occurrence and how SEVERE the impact would be on bulk power reliability for each of the following?

Please indicate H (High), M (Medium), or L (Low).

<table>
<thead>
<tr>
<th>Issue</th>
<th>Likelihood 1-5 Years</th>
<th>Likelihood 6-10 Years</th>
<th>Consequence 1-5 Years</th>
<th>Consequence 6-10 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emerging Issue #1</td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
</tr>
<tr>
<td>Emerging Issue #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emerging Issue #3</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Etc….</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>User Identified Issue</th>
<th>Likelihood 1-5 Years</th>
<th>Likelihood 6-10 Years</th>
<th>Consequence 1-5 Years</th>
<th>Consequence 6-10 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emerging Issue #1</td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
</tr>
<tr>
<td>Emerging Issue #2</td>
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<tr>
<td>Emerging Issue #3</td>
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<tr>
<td>Etc….</td>
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</tbody>
</table>
### Attachment II
#### Example Emerging Issue Submittal

**Emerging Issue #1: Accelerated integration of renewable capacity**

<table>
<thead>
<tr>
<th>Emerging Issue</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Horizon</strong></td>
<td>Number of years</td>
<td>10 years</td>
</tr>
<tr>
<td><strong>Background</strong></td>
<td>What is the change from the reference case?</td>
<td>Significant penetration of renewable and demand response resources (up to 15% of all energy)</td>
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<tr>
<td></td>
<td>What changes during the horizon?</td>
<td>Ramp to 15% energy should not be instantaneous, but at a rate that can be integrated while sustaining bulk power system reliability. Renewable and demand response resources in place at the end of 10 years.</td>
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<td>What is the impact to regional reliability?</td>
<td>Weather patterns of the region/subregion, the variety of renewable sources installed, the existing generation mix, and the bulk power system transfer capability with neighboring areas all influence amount of penetration of variable resources. Another consideration is the availability of ancillary services and system re-dispatch needed to support reliable operation.</td>
</tr>
<tr>
<td><strong>Assessment Factors</strong></td>
<td>Resource Adequacy Considerations [Yes/No]?</td>
<td>Yes. Significant changes in capacity mix: both in fuel and type. Incorporating both renewable and demand response will require new planning and operational strategies.</td>
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<tr>
<td></td>
<td>Transmission Adequacy Considerations [Yes/No]?</td>
<td>Yes. Significant increase in transmission requirements may be required to support the delivery of the renewable resources.</td>
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<td></td>
<td>Resource Siting Impacts [Yes/No]?</td>
<td>Yes. Wind is not a portable fuel and must be sited where it is prominent.</td>
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<td></td>
<td>Operations Impacts [Yes/No]?</td>
<td>Yes. Managing the variability of the generating resources and demand response will require more flexibility in the power system. The changes in the bulk power system flows from both the variable generation and demand response implementation must be better understood.</td>
</tr>
<tr>
<td><strong>Potential Study Scenarios (optional)</strong></td>
<td>Describe assumptions</td>
<td>Accommodate a minimum of an additional 15% of total energy from new renewable sources, with no more than 5% made up from energy efficiency. The base year for energy is 2008</td>
</tr>
<tr>
<td></td>
<td>Provide guidance on future studies</td>
<td>Substantial change in on-peak (demand response and variable/traditional capacity) and off-peak (variable generation) capacity mix could influence reliability, as planning approaches need more study. Namely, what are the appropriate tests to perform to ensure bulk power system reliability? Further, transmission requirements may significantly change.</td>
</tr>
</tbody>
</table>

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27 If “Yes” explain how this item could be affected
Appendix: NERC Reliability Assessment Procedures

b) Add instruction sheets
c) Data Forms
d) Discuss self-assessment narrative design and consistency
e) Sample Schedules/Work Plans
f) Provide templates and examples
Additional Reliability Assessment Information

In order for NERC to independently assess the reliability of the Reporting Regions, each Reporting Region should address additional potential issues that could significantly impact reliability. Such potential issues include, but are not limited to, the following:

a) Peak load uncertainties and variability due to extreme weather, economic conditions, fuel prices, etc.

b) Transient dynamics, voltage, or small signal stability issues.

c) Fuel Supply and Delivery interruptions.

d) Aging infrastructure.

e) Catastrophic Events/ Extreme Contingencies; for example, loss of a fleet of generator due to pipeline failure, loss of major import path, etc.