NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

ERO Reliability Assessment Process Document

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RELIABILITY | RESILIENCE | SECURITY




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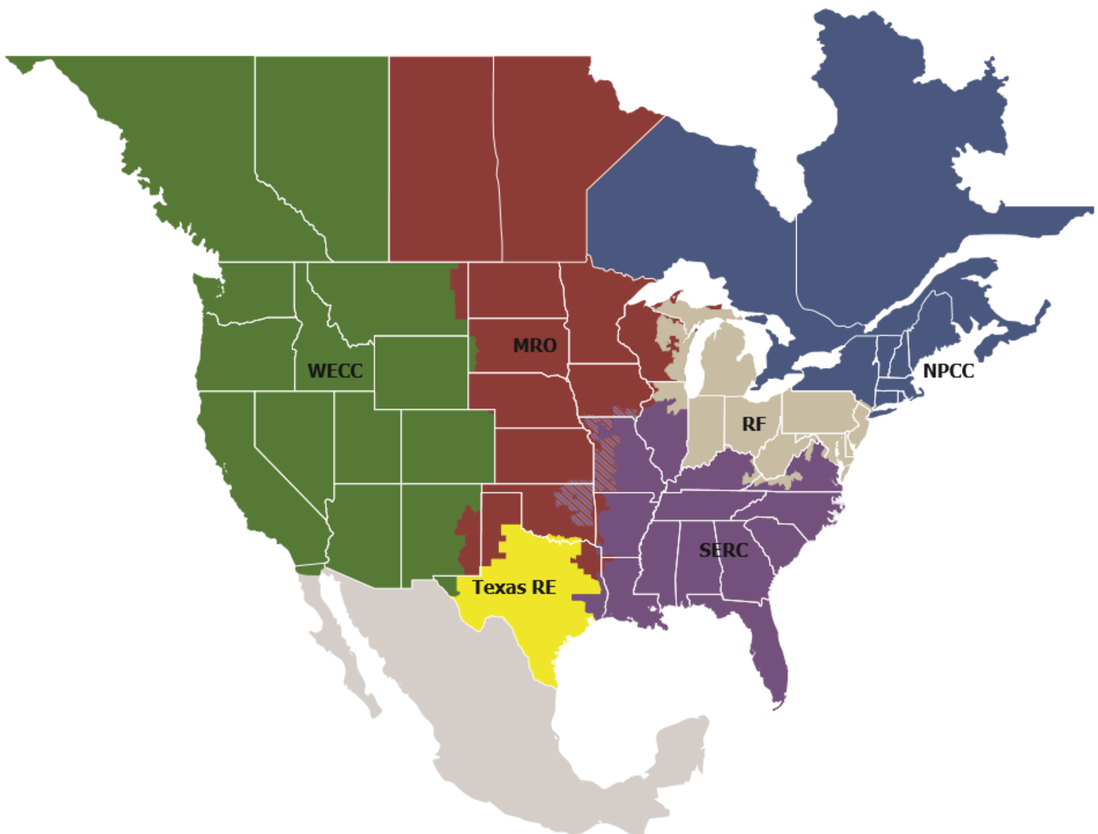
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

This process document describes analytical practices and processes for the NERC's reliability assessments, as defined in Section 800 of the NERC Rules of Procedure (ROP). The audience of the document includes the NERC Regions, registered entities, and other NERC stakeholders involved in the Reliability Assessment Process (e.g., the Reliability Assessment Subcommittee). As described in Section 805 of the ROP, this process document reviews the concepts, definitions, and agreed-upon practices that create the technical foundation for NERC's reliability assessments to create deliverables that are consistent, comprehensive, and complete. This process document provides an overview of how NERC's reliability assessments are developed, including objectives, deliverables, and data collection approaches. Probabilistic components of reliability assessment are documented separately in the Probabilistic Assessment Technical Guideline Document.

NERC's Reliability Assessment program depends on a collaborative and consensus-based approach that leverages engineering and analytical expertise across the ERO and other industry subject matter experts. The Reliability Assessment program provides unbiased judgment of the industry's plans for maintaining electric reliability in the future. This process document will be updated by NERC, with review by the ERO, as needed to ensure it appropriately reflects effective analysis to assess resource adequacy amid changing impacts to the North American BPS.

Reliability Assessment Program

NERC prepares the following assessments in accordance with the Energy Policy Act of 2005 and more specifically, Section 800 of the ROP:

- **Long-Term Reliability Assessment (LTRA)**: The annual long-term report shall cover up to a ten-year planning horizon, starting with the year following the year of data collection. The planning horizon of the Long-Term Reliability Assessment report shall be subject to change at the discretion of NERC.
- **Seasonal Assessments:** The annual Summer Reliability Assessment (SRA) report examines the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. The annual Winter Reliability Assessments (WRA) report examines the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands.
- **Special Reliability Assessments**: In addition to the long-term and seasonal reliability assessments, NERC and the Regions shall also conduct special reliability assessments on a Regional, inter-Regional, and interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees, stakeholder committees, or applicable governmental authorities. NERC will coordinate with the Regions to develop and approve special assessment scopes and to determine the necessary data and information required, with due consideration of stakeholder involvement.

NERC's Assessments

Assessment	Scope	Periodicity	Technical Committee Review/ Endorsement	MRC/BOT Review/ Acceptance
Long-Term	• 10-Year resource assessment • Emerging reliability issues • 5-Year probabilistic assessment	Annual *(Probabilistic assessment conducted biennially)*	Sept-Oct	Nov-Dec
Summer	• Seasonal resource assessment • Seasonal concerns/issues	Annual	May	N/A
Winter	• Seasonal resource assessment • Seasonal concerns/issues	Annual	Nov	N/A
Special (short-term and long-term)	• Topic-focused report requiring a comprehensive evaluation • Assessment generally focused on issues identified in the LTRA that require more analysis • Short-term special assessments can be developed for issues impacting the next 18-24 months	As Needed	2-4 weeks for comment and review; 1 week for endorsement	2 weeks for comment, review, and acceptance

Scope of the Reliability Assessment Program

The scope of the Reliability Assessment Program shall:

- Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected BPS, both existing and as planned.

- Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.
- Review, analyze, and report on RE self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.
- Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on BPS reliability.
- Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the BPS.

Reliability Assessment Framework

The following Reliability Assessment Framework provides guidance on the types of analysis needed to support the annual reliability assessments. This framework provides general guidance and responsibilities on what the ERO Enterprise evaluates for its reliability assessments. The following five objectives should be considered for each reliability assessment report and evaluated by the REs:

1. Adequacy of resources to meet demand and energy requirements
2. Sufficiency of Essential Reliability Services
3. Capability of the transmission system to accommodate projected resources and demand
4. Vulnerability to fuel supply, transportation, and delivery
5. Ability to manage extreme conditions (e.g., Adequate Level of Reliability[1])

Each of NERC's assessments should include the following in the front of the LTRA:

- **Findings**: findings that could be documented or referenced and that have importance to the assessment.
- **Conclusions**: deductions based on findings.
- **Recommendations**: statements that recommend actions a specific entity or entities should consider to address specific findings and conclusions.

NERC's assessments are based on the Reliability Assessment Framework outlined in the table below. NERC's data and assessment narrative guides provide additional detail and guidance on each topic area.

NERC Reliability Assessment Framework

Objective	Topic Area	Regional Entity Responsibilities
#1: Adequacy of resources to meet demand and energy requirements	Resource Adequacy	• Collect information and data to assess resource adequacy. • Analyze sensitivities to assess and examine resource adequacy under extreme conditions. • Determine resource adequacy for the first 5 years of the assessment period • Calculate and determine projected Anticipated and Prospective Reserve Margins (based on NERC's data instructions) • Biennially conduct a probabilistic resource adequacy assessment
	Emerging Issues	• Identify potential impacts or emerging issues that may negatively affect resource adequacy projections. • Identify resource changes needed to meet policy directives, e.g., Renewable Portfolio Standards. • Identify economic trends that may impact resource adequacy.
	Demand Forecasts	• Analyze demand forecasts and assess long-term trends (energy, peak demand, minimum demand, etc.) • Evaluate trends in demand, including normalized comparisons of forecasts to actuals. • Validate changes made by Planning Coordinators to forecast methods and assumptions.

[1] NERC definition of Adequate Level of Reliability.

Objective	Topic Area	Regional Entity Responsibilities
		• Identify and assess any unique conditions, such as growth in localized areas, distributed/behind-the-meter, economic factors, and boundary changes. • Identify drivers, trends, and emerging factors that are impacting demand.
	Resource Projections	• Identify new and retiring generation based on announcements, market auctions, integrated resource plans, etc. • Categorize new generation based on NERC supply/capacity definitions • Identify projected retirement dates of existing resources and identify units that are at-risk of retirement that may not be announced.
	Resource Availability	• Identify trends in resource availability, including identifying trends or changes in forced outage rates, outage causation, outage correlation, etc.
	Reference Margin Level	• Identify a Reference Margin level and compare it to Planning Reserve Margins for the first five years • Validate and determine reasonability of the Reference Margin Level provided (e.g., how does it relate to 1-day-in-10 LOLE resource adequacy target). • Identify risks and trends, such as significant changes to demand forecasts, increasing trends in generator forced outage rates, rapid growth in variable resources, and other factors that may invalidate the reasonability of the Reference Margin Level.
#2: Sufficiency of Essential Reliability Services	Frequency Support	• Identify changes to resources that may impact the system's ability to restore frequency following a major disturbance. • As an interconnection, determine whether an appropriate amount of frequency response reserves is being maintained. • Identify risks to the interconnection in the event that planned reserves could be inadequate for providing acceptable frequency response.
	Voltage Support	• Identify changes to resources and other system elements (e.g., flexible alternating current transmission (FACT) devices, synchronous condensers) that may impact the system's ability to maintain acceptable voltages during a major disturbance. • Identify risks to BAs' ability to ensure adequate reactive power and voltage support.
	Load Following/ Ramping	• Identify changes to resources and demand characteristics that create challenges or risks for BAs to respond to intraday ramping requirements. • Determine whether the future resource mix and transmission system can provide the needed ramping capability to support the largest expected 1- and 3-hour ramping requirements.
#3: Capability of the transmission system to accommodate	Transmission Adequacy	• Identify planned transmission additions and expansion projects throughout the assessment period. • Determine whether the transmission system, expected to be in place in 10 years, can reliably support the resources and demand

Objective	Topic Area	Regional Entity Responsibilities
projected resources and demand		projected in the 10-year plan (e.g., power flows, stability, deliverability). • Describe expected changes to Under Voltage Load-Shedding (UVLS) or Under Frequency Load Shedding (UFLS) schemes in your Assessment Area. • Summarize any transient dynamics, voltage, and small signal stability studies performed and any anticipated stability issues that could affect reliability during the study period. • Identify criteria for minimum dynamic reactive requirements or margins and how they are being applied to meet peak conditions. • Describe transient voltage-dip criteria, practices, or guidelines on the BPS and how they are being applied to meet the peak conditions.
#4: Vulnerability to fuel supply, transportation, and delivery	Fuel Adequacy/ Transportation / Availability	• Identify and assess potential reliability impacts caused by disruptions in fuel supply– particularly for natural gas-fired capacity.
		• Determine whether fuel transportation and delivery infrastructure is adequate to support projected resources through the planning horizon.
		• Evaluate the integration of fuel availability with BPS reliability including: ○ Fuel diversity of the generation fleet; ○ Potential unavailability of electricity generating facilities caused by short-term, generating fuel availability constraints; ○ Fuel transportation infrastructure, contracting issues and operating protocols; and ○ Dual fuel capability considering fuel availability, deliverability, technical limits (e.g., run time, cycling, ramping rate), economic considerations, environmental constraints and operating permits.
#5: Ability to manage extreme conditions (e.g., Adequate Levels of Reliability)	Resilience	• Assess (1) the robustness of the system in terms of its ability to absorb shocks and extreme stress; (2) the resourcefulness of system operators to manage extreme events; (3) the ability to recover rapidly; and (4) the adaptability of system operators and planners to incorporate lessons learned from past events. • Describe plans for responding to extreme weather or catastrophic events, for example, the loss of a fleet of generators due to the loss of a major pipeline or other fuel disruption, or loss of a major import path.

Data and Information Requirements

NERC collects all data and information from the industry through the eight Regional Entities, as detailed in Section 804 of the NERC Rules of Procedure and the Regional Entity Delegation Agreements.[2] Data requested could be identified as Critical Energy Infrastructure Information (CEII) or could introduce potential market sensitivities. Such

[2] Regional Entity Delegation Agreements.

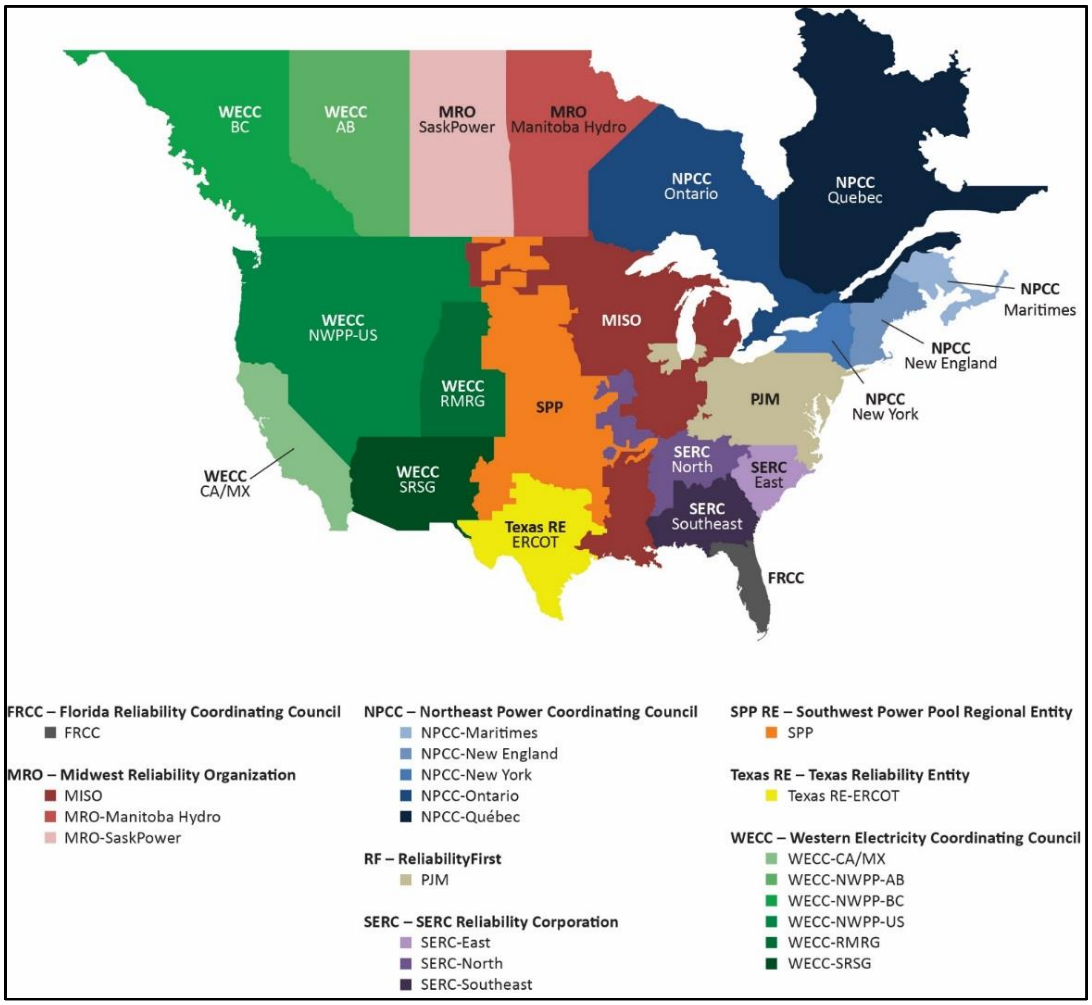
data will be treated in accordance with the provisions of Section 1500 (Confidential Information) of the NERC Rules of Procedure.[3]

Assessment Areas

For seasonal and long-term reliability assessments, unless otherwise directed, NERC collects data on an Assessment Area-basis. Assessment Areas, both within and across the eight Regional Entity boundaries are based on existing ISO/RTO footprints. Where ISO/RTOs are not established, Assessment Areas are based on the operating boundaries of an individual Planning Coordinator, or a group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated. For NERC's deterministic assessments, deterministic data should be collected as follows:

- Capacity and load data should be reported based on the physical or electrical boundary of each Assessment Area.
- Capacity and load data located outside the physical footprint of an Assessment Area, but electrically connected only to the Assessment Area's system, should be reported by that Assessment Area. The detailed output of peak capacity across boundaries to serve a neighboring Assessment Area's load should be reported as capacity transfer.

NERC Assessment Areas – 2017



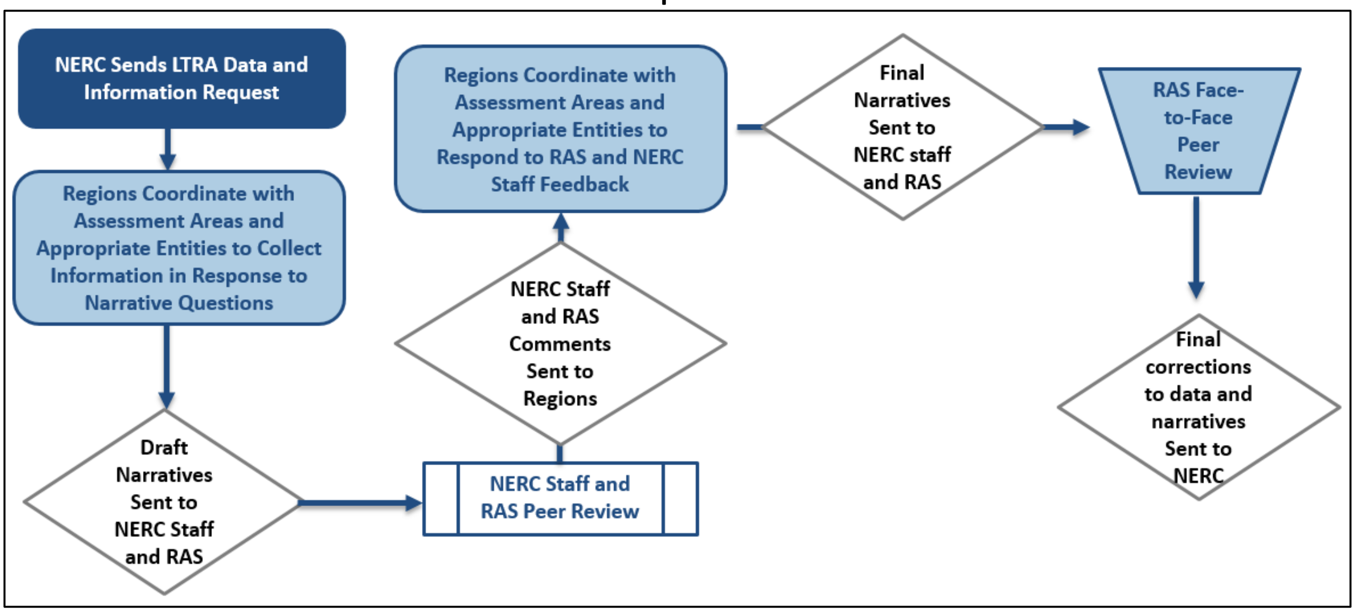
[3] NERC Rules of Procedure.

Several NERC Assessment Areas are based on existing, FERC-approved markets. Other Assessment Areas operate in the absence of markets. The availability of resources is often procured or modeled differently in market vs. non-market areas. This issue becomes more complex for long-term assessment because of the uncertainty involved in what generation gets built and how each Assessment Area accounts for future resources. Recognizing these differences among Assessment Areas, NERC has developed (through stakeholder processes) various definitions, categories, and concepts to provide a set of uniform approaches and reliability metrics for the entire North American BPS. NERC Assessment Areas are subject to change as a result of entities entering or exiting existing markets.

Assessment Development Processes

NERC's seasonal and long-term reliability assessments are based on data and information submitted by each of the eight Regional Entities. The Reliability Assessment Subcommittee (RAS) – under the direction of NERC's Planning Committee (PC) – supports NERC in the development of seasonal and long-term reliability assessments. The development process for the LTRA is presented in the figure below:

LTRA Development Process



Note: diamonds indicate when information, data, or documents are submitted.

The Assessment effort includes a peer review process that leverages industry subject matter expertise from various sectors of the industry. This process also provides an essential mechanism to ensure the validity of the data and information provided by the Regional Entities. Instructions on data submittal and timely subjects for group development within the self-assessments are provided to each Regional Entity prior to final submittal of the data and information used to develop NERC's assessments. Any other data sources used by NERC staff are identified in the report.

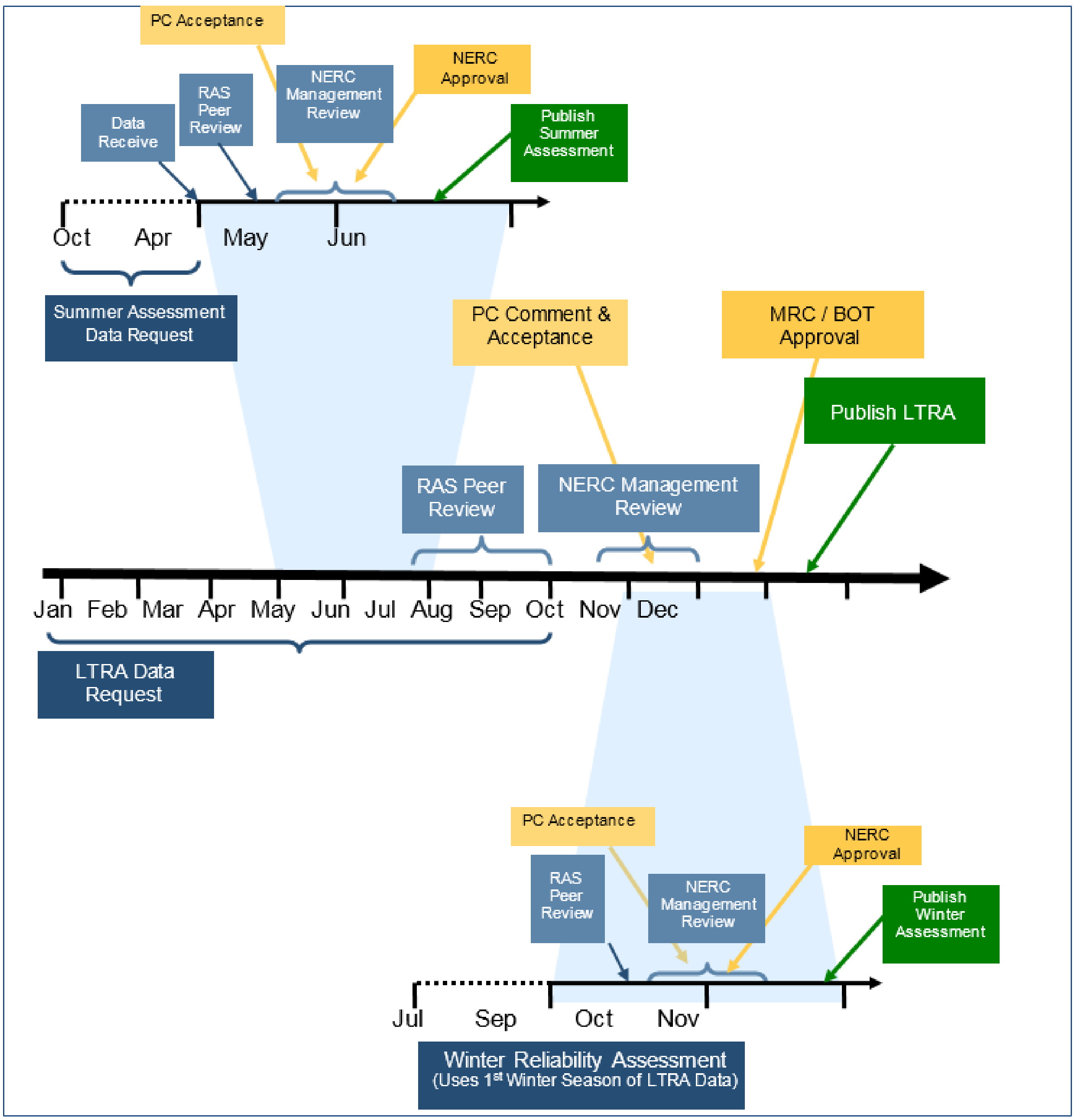
For the peer review process, each Assessment Area prepares its data and supporting narrative, which is assigned to two RAS members from other Assessment Areas for a comprehensive review. Reviewer comments are discussed with the Regional Entity's representative and refinements and enhancements are made as needed. The updated data and narratives are then subject to additional review by the entire subcommittee. This review ensures members of the subcommittee are informed of each area's self-assessment and data. It also provides an opportunity to share knowledge of planning processes through the industry. This process may be modified as deemed appropriate by NERC staff, through coordination with the RAS.

After NERC develops the report, NERC sends the draft for review by NERC's Planning and Operating Committees. After addressing comments and receiving approval from the PC, the final report is sent to NERC's Member Representatives Committee (MRC), NERC executive management, and NERC's independent Board of Trustees for final approval. This comprehensive vetting process ensures complete stakeholder support on NERC's independent assessment and the self-assessment from the Regional Entities, as well as supports NERC's mission as an independent organization.

Development Schedules

NERC, with input from the RAS, establishes schedules for each assessment on an annual basis. For the long-term and summer assessments, schedules are developed in January. The winter assessment schedule is developed in June. High-level schedules for NERC's three annual assessments are presented below:

NERC Reliability Assessments Development Schedules



Long-Term Reliability Assessment

The annual long-term report shall typically cover a ten-year planning horizon, but can be modified at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

The annual LTRA request (send to the Regional Executives) includes posted materials that provide required deliverables for each Region and Assessment Area, including:

- **Narrative Guide**: a series of questions related to topics outlined in this guidebook, as well as potential reliability risks.
- **Data Forms**: a series of Excel spreadsheets to capture resource adequacy data outlined below.
- **Data Instructions**: definitions, concepts, and guidance on populating the LTRA data forms.

Resource Adequacy Assessment

The resource adequacy assessment evaluates the demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Assessment Area. The Regional Entities independently evaluate the ability of each Assessment Area to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including Anticipated and Prospective resources, as explained in the Capacity Assumptions section. If the Assessment Area relies on capacity from external sources to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements and/or Reference Margin Levels for each Assessment Area for the year(s) or season(s) being assessed. The REs shall determine if the resource information submitted represents a reasonable and attainable plan for the Assessment Areas. NERC requests that the RE identify cases of inadequate capacity or significant resource uncertainty (based on engineering judgement), and shall provide additional analysis and explain conditions and plans to mitigate the reliability impacts of the potential inadequacies. The analysis may be expanded to include surrounding areas (i.e., neighboring Assessment Areas). If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regional Entities. The assessment report will include descriptions of the results of these analyses (if available); otherwise, the assessment should include action plans or mitigating strategies to address any resource inadequacies.

The resource adequacy analysis includes an in-depth examination of the following data:

- The projected electricity demand during the peak hour for the summer and winter (with consideration for demand-side resources);
- The projected available existing and planned capacity;
- The projected available capacity transfers during the peak hour being assessed; and
- The projected Reference Margin Level(s).

NERC collects projected peak demand, as well as data on existing and planned capacity and net capacity transfers (between Assessment Areas) for the summer and winter seasons. Resource planning methods vary across entities throughout North America. To promote consistency, NERC has collaborated with industry stakeholders to establish a uniform approach for collecting and presenting resource adequacy data. This approach is described below.

Demand Assumptions

The forecasted peak demand is weather-normalized and collected on a coincident basis for each Assessment Area. Aside from these guidelines, load forecasting methods used by each Assessment Area depending on how they model the following variables:

- Economic growth; examination of different economic sectors (e.g., residential, industrial, commercial)
- Energy Efficiency and conservation impacts
- Energy diversity
- Localized impacts (e.g., large factories or data centers)

Demand is collected with the following categories:

Total Internal Demand: The projected sum of the net outputs of all generators within the system and the line flows into the system, less the 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. Total Internal Demand should be reduced by indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-controllable or non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs), and distributed energy resources. Total Internal Demand should not be reduced by the projected impacts of Controllable and Dispatchable Demand Response programs. Peak demand forecasts are weather-normalized and collected on a coincident basis for each Assessment Area. Load forecasting includes consideration for the following:

- **Projected economic outlook**: The condition of the economy is closely tied to electricity use. Some sectors further examine economic outlook by sector (e.g., industrial, residential, commercial). Localized pockets of higher or lower load growth are should also be examined.
- **Estimated Diversity**: the electric utility system's load is made up of many individual loads that make demands upon the system usually at different times of the day, month, or season. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.
- **Stand-by Load under Contract**: demand which is normally served by behind the meter generation which has a contract to provide power if the behind-the-meter generator becomes unavailable.
- **Demand-Side Management**: Demand-Side Management (DSM) can be divided into three components: Demand Response (DR), Conservation and Energy Efficiency.
- **Conservation**: a reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit or using occupancy sensors that turn off lights or appliances.
- **Energy Efficiency:** 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. Energy Efficiency is typically incorporated into an area’s load forecast.

- **Demand Response (DR)**: programs are designed to alter the timing of electric use from 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 demand, or when required to maintain system reliability. Applicable Demand Response programs include those in which the System Operator has physical (Controllable) command to activate the program based on instruction from a control center. Controllable and Dispatchable Demand Response includes four categories: Critical Peak Pricing (CPP) with Load Control; Direct Control Load Management (DCLM); Load as a Capacity Resource (LCR); and Interruptible Load (IL). For NERC's deterministic assessments, Demand Response programs are treated consistently as a load-modifier, despite market design impacts or applications of these programs in certain Assessment Areas.

Net Internal Demand: equal to Total Internal Demand, reduced by the amount of Demand Response programs projected to be available during the peak hour. Net Internal Demand is used in all Reserve Margin calculations.

The table below further explains how different demand attributes are incorporated into the demand forecast for the LTRA:

Demand Attributes

Item	Add/Subtract
Unrestricted Non-coincident Peak	**Starting Point**
New conservation (Energy Efficiency)	Subtract
Estimated Diversity	Subtract
Standby Demand (normally served by behind-the-meter generation)	Add
Distributed Energy Resources	Subtract
Total Internal Demand	**Total**
Dispatchable, Controllable Demand Response	Subtract
Net Internal Demand	**Total**

Capacity Assumptions

NERC collects unit level data for all capacity expected to serve peak load. Associated data includes: operating status, country, plant name, prime mover, primary and secondary energy source, initial operating month/year, confirmed retirement date, nameplate capacity, summer capacity, and winter capacity. Additional information and instructions for NERC's assessments are available in the latest data instructions for NERC's Long-Term Reliability Assessment.[4] The following guidelines should be applied when reporting capacity data:

Capacity should be reported at a plant-level for all wind, solar, and hydro resources. All other capacity will be reported for each unit for the summer and winter peak hour using the following categories:

Certain Capacity: generating capacity includes existing or planned capacity expected to be available to serve load during the peak hour with Firm transmission service, meeting at least one of the following requirements:

- Unit must have a firm capability and have a Power Purchase Agreement (PPA) with firm transmission in effect for the unit at the time of peak demand
- Unit must be classified as a Designated Network Resource
- Where energy-only markets exist, unit must be a designated market resource eligible to bid into the market

[4] The latest LTRA instructions are available on the Reliability Assessment Subcommittee (RAS) website.

Other Capacity: generating capacity that should be available to serve load during the peak hour, but lacks Firm transmission service, does not meet at least one of the requirements of Certain Capacity, or could be unavailable to serve peak load.

Variable Resources: generation that is variable in nature (e.g., wind, solar, and run-of-river hydro) are collected in the capacity categories defined above. For example, a wind plant rated with a nameplate capacity of 100 MW may be projected to serve 10 MW during the peak hour. In this example, the derated 90 MW is not counted as available capacity during the peak (and not directly reported in the data). The amount of capacity available to serve peak load for variable resources should be based on analysis that includes either a probabilistic representation or modeled based on historic performance, as determined by the Assessment Area or Region. Consolidated projections of variable resource capabilities on a resource type (e.g. wind, solar, etc.) within an Assessment Area are acceptable.

Future capacity additions are reported in three categories, primarily based on the FERC Interconnection Requirements:

Tier 1: included in the Anticipated Resources category, planned generating unit or plant that meets at least one of the following requirements:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection Service Agreement (ISA)
- Signed/approved Power purchase agreement (PPA)
- Signed/approved Interconnection Construction Service Agreement (CSA)
- Signed/approved Wholesale Market Participant Agreement (WMPA)
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)

Tier 2: included in the Prospective Resources category, planned generating unit or plant that meets at least one of the following requirements:

- Signed/approved Completion of a feasibility study
- Signed/approved Completion of a system impact study
- Signed/approved Completion of a facilities study
- Requested Interconnection Service Agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)

Tier 3: other planned generating units or plants that do not meet any Tier 2 requirements.

Accounting for unavailable capacity: NERC also collects data on the potential unavailability to existing and future generating capacity, including scheduled outages and transmission limitations caused by known physical deliverability limitations to serve load that the resources are obligated to serve.

Projected capacity retirements are defined as follows:

Confirmed Retirement: capacity with formalized announced plans to retire; where applicable, the unit must have an approved generator deactivation request. Confirmed retirements are captured as a reduction from Anticipated Resources.

Unconfirmed Retirement: capacity that has been earmarked for retirement. Unconfirmed retirements are captured as a reduction from the Prospective Resources. Examples include:

- Reliability, must-run status and other issues may conflict with this proposed/requested retirement or unit conversion (e.g., from a coal unit to a gas unit).
- Units that have submitted a request for a generator deactivation request, but have not received approval.
- Units expected to retire based on the result of a generator survey or Assessment-Area resource adequacy study.
- Units that are earmarked for retirement, or at-risk based on economic analysis (e.g., production cost model).

Resource Availability and Fuel Assurance

The overall adequacy and availability of resources to serve load is of critical importance for maintaining BPS reliability. The consideration and integration of fuel assurance is an essential element of a reliability system.

- **Fuel Assurance**: confidence or certainty in the supply, availability and deliverability of fuel to electric generation, which can include the firmness of generator fuel arrangements.

Registered Entities, along with REs, should perform assessments to identify reliability risks associated with the potential availability of load serving resources. Assessments should focus on the following potential risks to load serving capability within the Assessment Areas, in consideration of the roles of NERC Planning Coordinators (PC) and Balancing Authorities (BA):

- Identify resource issues related to fuel assurance that could lead to reliability risks;
  - Quantifiable fuel assurance of Assessment Areas including an assessment of variable resource penetration levels; examples include:
    - Dual fuel capability as a percentage of overall capacity;
    - Amount of capacity with on-site fuel;
    - Assessment of fuel switch-over success during extreme weather events;
    - Firm contracts available to natural gas generation;
    - Overall fuel diversity within the resource mix; and
    - Amount of variable resources and their contribution during summer and winter peak periods.
  - Identify risks and mitigation of resource assurance data for an Assessment Area
  - Assess potential policy and market driven impacts to resource availability
    - Evaluate accelerated retirements due to economic drivers or fuel costs
- Identify resource issues related to fuel availability that could lead to reliability risks;
  - Assess potential policy and market driven impacts to fuel availability (e.g., coordination of gas and electric days)
  - Assess resource fuel delivery infrastructure and risks to that infrastructure

- Assess mitigation of potential fuel delivery infrastructure issues.
  - Assess the use of dual fuel capability resources and how their use is used to mitigate infrastructure and operational challenges
  - Dual Fuel capability should consider fuel availability, inventories, deliverability, technical limits (e.g., run time, cycling, ramping rate) and operating permits
  - Assess levels of fuel availability and infrastructure from a contractual perspective (e.g. firmness of supply and delivery of coal, natural gas, etc.)

- Identify potential variable resource issues that could lead to reliability risks:
  - Assess how potential policy or market changes could impact the operation of variable resources
  - Assess the operational issues, such as ramping capability or the limited flexibility for operators
  - Assess resource assumptions related to capacity for variable resource plans
  - Assess potential variable resource infrastructure and risks to that infrastructure
  - Assess mitigation of potential variable resource issues.
- Present results of analysis to decision-makers and suggest short- and/or long-term mitigation strategies and present other conclusions and recommendations that can be shared with the industry.

Overall, assessments should evaluate whether an Assessment Area can operate reliably within the expected range of resource availability, under expected operating conditions during the assessment period.

Resource Categories and Reserve Margins

The Reserve Margin is an important planning metric used to examine future resource adequacy. This deterministic approach examines the forecast peak net internal demand (load) and projected availability of capacity to serve the forecast peak demand. The Reserve Margin provides an indication of how well-protected a system is from disconnecting firm load.

Planning reserve margins are designed to measure the amount of generation capacity available to meet expected demand in planning horizon. Coupled with probabilistic analysis, the planning reserve margin metric is an accepted industry measure used by planners as a relative indication of system adequacy.

Planning Reserve Margins equal the difference in Anticipated or Prospective Resources and Net Internal Demand, divided by Net Internal Demand. Generally, the projected demand is based on a 50/50 forecast.[5] For systems that are not energy-constrained, the reserve margin is the difference between available capacity and peak demand, normalized by peak demand and presented as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g. extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, planning reserve margin trends identify whether capacity additions are keeping up with demand growth. As this is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources.

Reserve Margin projections are based on two resource categories, Anticipated and Prospective (defined in the prior section).

[5] Essentially, this means that there is a 50 percent probability that actual demand will be higher and a 50 percent probability that actual demand will be lower than the value provided for a given season/year.

Anticipated Resources

- Existing and Planned Tier 1 Certain Capacity (includes reductions for Confirmed Retirements)
- Net Firm Imports/Exports

Prospective Resources

- Anticipated Resources
- Other Capacity Adjustments (described in instructions)
- Tier 2 capacity additions
- Net Expected Imports/Exports
- Unconfirmed Retirements

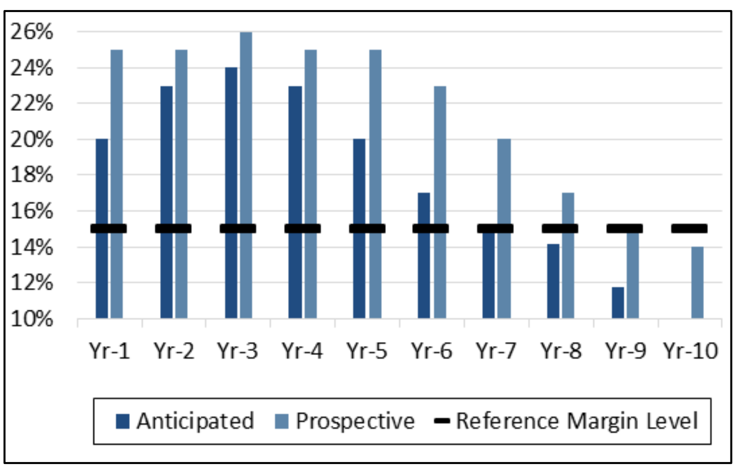
There are two Reserve Margin categories (one for each Resource Category):

$$\textbf{Anticipated Reserve Margin} = \frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

$$\textbf{Prospective Reserve Margin} = \frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

Anticipated Reserve Margin is based on planning data with the highest level of certainty. An example of the interplay between Anticipated and Prospective Reserve Margins is provided below. In the short-term, capacity additions exceed the increase in load growth. In the long-term, fewer anticipated resources are projected while load continues to grow. Prospective resources, while less-certain, are projected to meet the reference margin level until the last two years of assessment. During the final two years, Tier 3 resources or future identification of demand-side tools can be considered to address a potential resource adequacy concerns.

Reserve Margin Example



The Anticipated Reserve Margin is the primary metric that is used to evaluate the adequacy of projected resources to serve forecasted peak load. Having a shortfall of reserves indicates that an assessment area would fall below their target Reference Margin Level, and increases the risk of a loss of load.

Reference Margin Level

The Reference Margin Level is usually established by a regulatory authority within the Assessment Area and is typically based on the load, generation, and transmission characteristics. In some cases, the Reference Margin

Level may reflect a Region's compliance requirements, or a requirement or target level implemented by an individual state(s), provincial authority, ISO/RTO, or other regulatory body. If such a requirement or target exists, the applicable Assessment Area generally applies it as the Reference Margin Level. The Reference Margin Level be different for each season and/or year of the assessment period.

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.

In cases where an Assessment Area or Region does not provide a Reference Margin Level, the Region shall apply one based on their independent study or engineering judgement.

The ERO assessments of the Reference Margin Level includes:

- Identifying a Reference Margin Level and comparing it to Planning Reserve Margins for the first five years:
  - This involves evaluating the data collected, and comparing the Anticipated and Prospective Reserve Margin projections to the Reference Margin Level for each Assessment Area for the first five years. If there are any resource deficiencies identified during the 10-year assessment period, this should be further evaluated by the Region (e.g., is the deficiency manageable? Are there additional Tier 2 or Tier 3 resources available? Are there any pending regulatory actions?).
- Validating and determining reasonability of the Reference Margin Level provided:
  - Regional Entities should critically evaluate processes and analysis used to establish the Reference Margin Level for each Assessment Area. This should include consideration of the projected resource mix and whether or not the projected Reference Margin Level applies consistently through each season of the 10-year period.
- Identifying risks that may invalidate the reasonability of the Reference Margin Level
  - Regional Entities should determine if the following impact the Reference Margin Level:
    - At-risk unit retirements that may not be captured as either Confirmed or Non-confirmed retirements;
    - Rapid and concentrated penetration of distributed energy resources (DERs);
    - Fuel assurance and contribution of variable energy resources;
    - Significant demand uncertainty;
    - Considerations for availability of resources and potential demand changes for each season; and
    - Other energy limitations.

Probabilistic Assessments

Probabilistic components of reliability assessment are further described in the *Probabilistic Assessment Technical Guideline Document*.[6] Results of the probabilistic assessments are included in the LTRA on a biennial basis.

Assessment of Essential Reliability Services (ERS)

Future system reliability assessments need to consider additional operational reliability concerns which are dependent on the time frame of the assessment. These analyses should surpass evaluating the forecasted peak

[6] Probabilistic Assessment Technical Guideline Document.

load and projected generation to include the analysis of Essential Reliability Services (ERS). The considerations for ERS analysis can be separated into near-term (1-5 years) and long-term (6-10) timeframes. Below are sample questions for each category. The answers to these questions will drive future data collection activities and analysis.

Near term (operational) ERS considerations
In the near term assessment period the following query can be used by the BAs, TOs, and TPs in each Assessment Area:

- During a disturbance (i.e. loss of generation or transmission), what is the minimum inertia that needs to be maintained to prevent the Rate of Change of Frequency (RoCoF) from reaching a frequency below the set point for the first stage of under frequency load shedding?
- Do the system operators know:
    - Which generators have governors and have enabled frequency response?
    - Which generators have their governor response in blocking mode?
    - Which generators will withdraw primary frequency response due to an override by the plant control systems?
    - How much generation is Behind-the-Meter (BTM), serving as a reduction to load?
    - How much generation can be classified as an inverter-based resource and where is it located (BTM or utility connected)?
    - Which generators operate using Automatic Voltage Regulation (AVR) as opposed to maintaining a constant power factor setting?
- Do the projected daily and 24-hour day ahead ramps exceed available resources capabilities (e.g. on-line, quick-start, etc.), thus posing a risk to generation and load system balance?
- Has the TO coordinated with the appropriate Distribution Providers to ensure BTM inverter-based resources align with the TO's needs, in accordance with the latest version of IEEE-1547?

Long-term (planning) ERS considerations
In the long term assessment period the following query can be used by each Assessment Area and/or BA:

- Does the area have the ability to adequately balance generation and load during normal conditions within their area, meet the shared responsibility of supporting interconnection frequency, and also maintain sufficient capacity to meet contingency reserves and frequency response obligations?
- Has the area examined the composition of the generation fleet to determine if changes are needed in the supply procurement, unit commitment or dispatch practices?
- Have inverter based resources reviewed their disturbance ride through capabilities and set appropriate time delays for tripping or current injection blocking?

The questions above for the given time-frames categories provide insights into the assumptions about the expected operational characteristics of BPS resources. These sample inquiries focus on capturing the evolution of the power grid from large synchronous machines with rotating masses to a more varied resource mix composed of inverter-based resources and smaller synchronous machines. As the transformation progresses the way the power grid is planned and operated must change to ensure the fundamental reliability operating characteristics are accounted for in the system, and to ensure that any gaps can be identified before adverse impacts on reliability occur. The following ERS building blocks are the fundamental characteristics that are required to be provided to support reliable system operations regardless of the resource mix composition.

- **Voltage Support:** Required to maintain system-level voltages on the BPS within established limits, under pre-contingency and post-contingency situations, thus preventing voltage collapse or system instability.[7]
- **Frequency Support:** Required to support stable frequency on the synchronized BPS and to maintain continuous load and resource balance by employing automatic response functions of a resource in response to deviations from normal operating frequency. The BPS must have the ability to raise or lower generation or load, automatically or manually, under normal and post-contingency conditions.[8]
- **Ramping Capability:** Ramping is using real-power control to raise or lower resources over a period of time to maintain load generation balance. Ramping capability is most needed at times of major load changes, such as morning ramp-up, afternoon ramp-down, and evening ramp-up. However, with the integration of large amounts of variable resources, such as photovoltaics, wind, and off-peak electrical loads (e.g., electric vehicles and smart appliances), ramping needs may also change to off-peak ramps.[9]

In an effort to address ERS questions, The NERC Planning Committee and Operating Committee jointly created the Essential Reliability Services Task Force (ERSTF) to consider reliability issues that may result from the changing generation resource mix. This resulted in the development of ten initial ERS measures for examination and monitoring to identify trends[10]. The ERSTF was converted into a working group and was charged with identifying, evaluating, further developing and investigating the practicality of each quantifiable measure[11]. The most important essential reliability services (ERS) for reliability largely focus on the topics of managing voltage, frequency, and net demand ramping.

Recommended ERS measures were created to address the identified reliability risks to the ERS building blocks. Since the creation of the ten initial ERS measures, the measures have been evaluated by NERC and the industry and necessary changes to measures have been implemented. Additionally, some measures have been determined to be ineffective and their use has been discontinued. Please visit the NERC ERS homepage for the most up to date information on ERS measures and how they are being applied to industry. The following table includes a list of the ERS measures and the responsible group/action for both historic reporting (past performance) and forward looking projections.

ERS Measures – Historic Reporting

ERS Framework Measure	Group / Action
Measure 1 : Synchronous Inertial Response at an Interconnection Level	Resource Subcommittee
Measure 2 : Initial Frequency Deviation Following Largest Contingency	Resource Subcommittee
Measure 3 : Synchronous Inertial Response at the BA Level	No Further Action
Measure 4 : Frequency Response at Interconnection Level	Resource Subcommittee
Measure 5: Real Time Inertial Model	Industry Practice
Measure 6 : Net Demand Ramping Variability	Resource Subcommittee
Measure 7 : Reactive Capability on the System	No Further Action
Measure 8 : Voltage Performance of the System	No Further Action

[7] NERC ERS Final Measures Framework Report
[8] ibid
[9] ibid
[10] ibid
[11] NERC ERS Whitepaper on Sufficiency Guidelines

Measure 9 : Overall System Reactive Performance	Industry Practice
Measure 10: System Strength	Industry Practice

ERS Measures – Historic Reporting

ERS Framework Measure	Group / Action
Measure 1 : Synchronous Inertial Response at an Interconnection Level	NERC RA Process
Measure 2 : Initial Frequency Deviation Following Largest Contingency	NERC RA Process
Measure 3 : Synchronous Inertial Response at the BA Level	No Further Action
Measure 4 : Frequency Response at Interconnection Level	NERC RA Process
Measure 5: Real Time Inertial Model	Industry Practice
Measure 6 : Net Demand Ramping Variability	Reliability Assessment Subcommittee
Measure 7 : Reactive Capability on the System	No Further Action
Measure 8 : Voltage Performance of the System	No Further Action
Measure 9 : Overall System Reactive Performance	Industry Practice
Measure 10: System Strength	Industry Practice

As ERS relates to forward-looking assessments, REs should evaluate the changing system in regards to the following:

Frequency Support (REs should examine this measure at the interconnection level)

- Identify changes to resources that may impact the system's ability to restore frequency following a major disturbance.
- As an interconnection, determine whether an appropriate amount of frequency response reserves is being maintained.
- Identify risks to the interconnection in the event that planned reserves could be inadequate for providing acceptable frequency response.

Voltage Support

- Identify changes to resources and other system elements (e.g., FACT devices, synchronous condensers) that may impact the system's ability to maintain acceptable voltages at all times.

Load Following/ Ramping

- Identify changes to resources and demand characteristics that create challenges or risks for BAs' abilities to respond to intraday ramping requirements.
- Determine whether the future resource mix and transmission system can provide the needed ramping capability to support the largest expected 1- and 3-hour ramping requirements.

NERC Electricity Supply and Demand Database

NERC staff maintains and annually publishes Electricity Supply & Demand (ES&D) database for North America, encompassing both current and historical long-term capacity and demand projections. The ES&D includes aggregated ten-year projections of electricity demand, electric generating capacity, and transmission line mileage that NERC uses to develop the annual LTRA.

Transmission and Capacity Transfers

NERC collects projections for new transmission projects, including details on voltage class, line length, origin point/end point, line carrying capability, and expected in-service dates. In addition to this information collected and presented on the BPS, NERC also collects the following data on transfer capacity to assess deliverability and constraints:

- **Firm Imports/Exports**: Capacity intended to meet the demand requirements of utilities' customers; the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. There are two subsets:
  - **Full Responsibility Purchases**: A firm contract for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load customers.
  - **Owned Capacity/Entitlement Located outside the Area**: A transfer in which owned capacity is located outside the reporting Assessment Area's boundary.
- **Expected Imports/Exports**: Projected transfers with a high expectation that a Firm contract will be executed.
- **Transmission Limitations**: Capacity projected to be unavailable due to transmission limitations caused by known physical deliverability limitations to serve load that the resources are obligated to serve.

Guidelines for Transmission Reliability Assessment Reviews

REs are to perform assessments to identify potential future reliability risks. Assessments should consider:

- Identifying issues that could lead to reliability risks;
- Presenting analytical results understandably to enable decision-makers to apply analytical results;
- Suggesting short and/or long-term mitigation strategies and present other conclusions and recommendations that can be shared with the industry.

Overall, assessments should evaluate whether an Assessment Area can operate reliably under the expected range of operating conditions over the assessment period, as required by NERC reliability standards. Assessments should also identify issues specific to sub-areas of the system that are especially critical to the reliable operation of the BPS along with mitigation strategies to resolve the issues. Assessments should focus on the following potential transmission considerations within the Assessment Areas, in consideration of the roles of NERC Planning Coordinators and Transmission Planners.

NERC recommends the following guidance be considered when developing Reliability Assessments:

- Describe the key question you would like to answer with each of your reliability assessments and how the answer to these questions will help to identify potential reliability risks.

- Describe expected increases to Under Voltage Load-Shedding (UVLS) or Under Frequency Load Shedding (UFLS) schemes in your Assessment Area. Include the amount of load (MW) targeted for protection against resource mix changes and cascading events.
- Describe and summarize:
  - Planning studies performed that analyze significant risks to the BPS, (e.g., TPL-001-4 studies on extreme events[12]); this should include any reliability issues identified and plans to address them.
  - Specific studies performed within the Assessment Area to address uncertainties, such as load forecast errors, resource mix changes and extreme weather events.
  - Any transient dynamics, voltage, and small signal stability studies performed and any anticipated stability issues that could impact reliability during the study period.
- Identify criteria for minimum dynamic reactive requirements or margins and how they are being applied to meet peak conditions.
- Describe transient voltage-dip criteria, practices, or guidelines on the BPS and how they are being applied to meet peak demand conditions.
- Describe any dynamic and static reactive power-limited areas on the bulk power system in your Assessment Area and plans to mitigate them. Include criteria for voltage stability margin and explain how they is being applied to meet the peak conditions.
- Describe how neighboring BAs, PCs, and TPs coordinate with each other and how seams issues are addressed, including contingency lists, tie line data, model sharing, protection system coordination, generation dispatch, and generation additions/retirements.
- Describe new technologies, systems, and/or tools that are expected to be deployed to improve BPS reliability.
- Describe the relationship between transmission analyses and resource adequacy studies including whether they are independent analyses or whether one is treated as an input to the other. If transmission results are an input into a resource adequacy study, describe that process.

[12] Reliability Standard: TPL-001-4.

Seasonal Reliability Assessment

NERC and the Regions will evaluate the overall operating reliability of the regional BPS on a seasonal basis. In Assessment Areas with potential resource adequacy or system operating reliability concerns, operational readiness of the affected REs for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the RE's ability to deal with the situations that might occur during the upcoming season.

Typical activities in the assessment may include:

- Facility modifications and additions;
- Any unusual operating conditions that could impact reliability for the operating period
- New or modified operating procedures;
- Fuel supply adequacy;
- Emergency procedures enhancement; and
- Planning and operating studies.

NERC will report the overall seasonal operating reliability of the BPS in the annual summer and winter assessment reports. NERC's seasonal assessments will use a deterministic approach to consider the impacts of potential variables that may affect the availability of resources to meet the summer or winter peak electrical demand for each Assessment Area.

The standard approach to assessing resource adequacy for the upcoming season is to account for normalized projected demand and resources and to identify planning reserves (*i.e.*, resources in excess of peak demand) to cover the uncertainty in peak demand and resource availability to meet a one-in-ten-years loss-of-load event benchmark, based on probabilistic analysis. Seasonal assessments are intended to illustrate the range of resource adequacy outcomes that might occur and can include several sensitivity analyses by varying the value of certain parameters that affect resource adequacy. The variation in these parameters is based on historic values of these parameters or adjustments by any known or expected changes.

Seasonal resource adequacy metrics are collected and presented similarly to the LTRA, with considerations for near-term resource availability impacts (e.g., outages, near-term transmission limitations, operational issues) expected for the peak operating periods for the summer and winter.

Data and Information Collection

Sections that relate to demand assumptions, capacity assumptions, and transmission assumptions are similar to those described in the LTRA section. Data is collected through a separate request for the summer assessment. Due to the timing of data collection for the LTRA, and to avoid multiple data requests, winter data from the LTRA submission is used for the winter assessment. This data is reviewed and updated as necessary by the appropriate Assessment Area and Region to ensure the winter assessment has the most current data included prior to publication. Regions and Assessment Areas should coordinate with appropriate Registered Entities to review the latest studies, outage schedules, and other impacts that might affect the availability of resources for the upcoming season.

The annual seasonal assessment requests (sent to the Regional Executives) include posted materials that provide required deliverables for each Region and Assessment Area, including:

- **Narrative Guide**: a series of questions related to topics outlined in this guidebook, as well as potential reliability risks.
- **Data Forms**: a series of Excel spreadsheets to capture resource adequacy data outlined below.
- **Data Instructions**: definitions, concepts, and guidance on populating the seasonal data forms.

The narrative guide includes questions that examine:

- Emerging reliability issues for the upcoming season that are unique to the Assessment Area.
- Details regarding the drivers, likelihood of impact, and a timeframe for each issue.
- Potential operational challenges, including:
  - Fuel shortages,
  - Over-generation during light-load conditions;
  - Insufficient essential reliability services;
  - Extended or unusual generation outages
- Special operating studies (including any extreme weather conditions, drought studies, etc.) performed or to be performed for the upcoming season.
- Unique operational challenges recently observed and how they were mitigated. (Discuss the timing of these studies, date the assumptions are approved and date the studies are released).
- Any significant issues; examples include: extended transmission or generation outages that could impact reliability, modification to existing operational procedures, increased dependency on transfers, or identification of critical units for seasonal reliability, identified in neighboring Assessment Areas, subregions, or across any other inter and intraregional areas that have the potential to impact operations. Additionally, identify the means in which these issues are coordinated and communicated between the neighboring areas.

Operational Risk Analysis

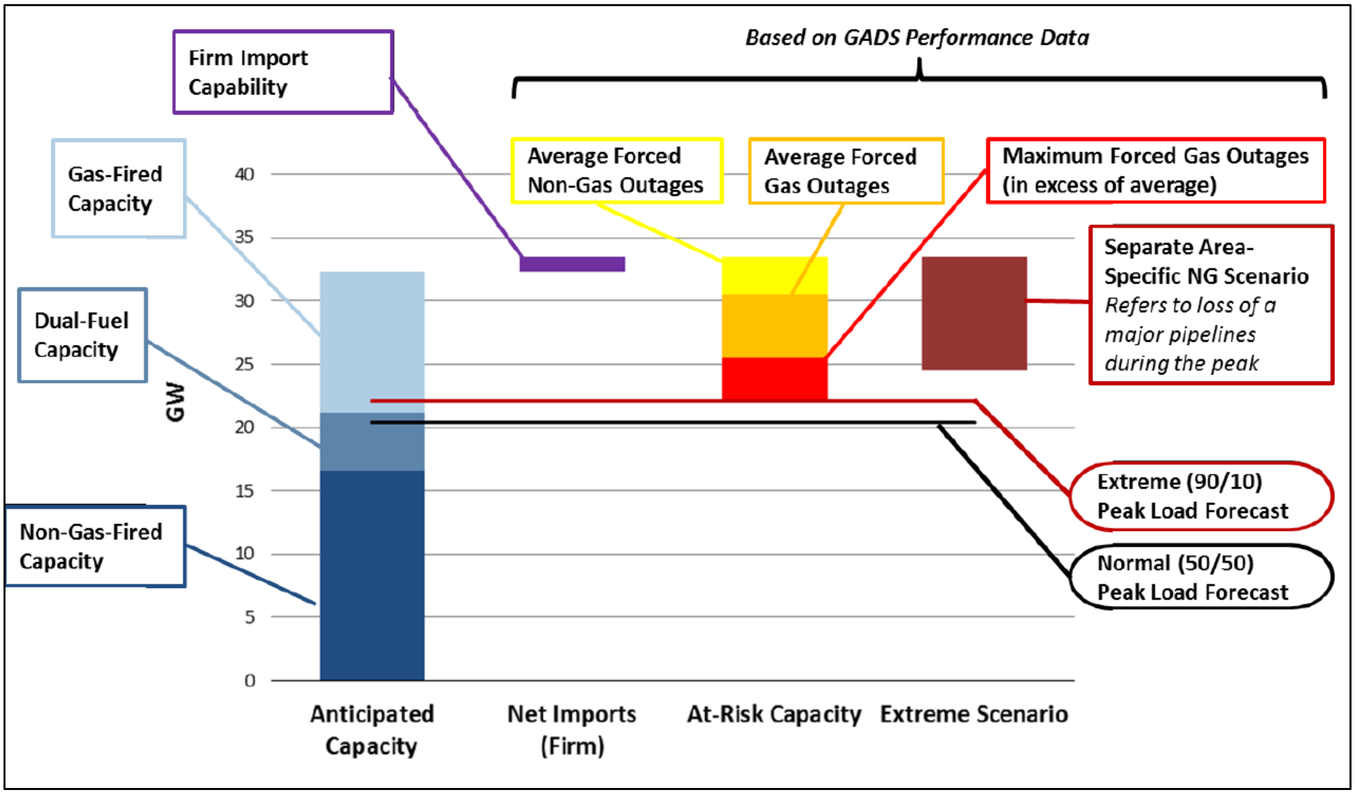
NERC continues to refine the framework for the operational risk analysis and is working with the RAS to develop a more consistent approach.

NERC's operational risk analysis can be used in seasonal assessments and other special assessments. This approach applies data used to develop a traditional planning reserve margin, while also incorporating operational sensitivities for a given system, based on past performance of capacity used to serve peak demand. This involves highlighting the potential unavailability of at-risk capacity (based on actual performance data) during the peak hour, while also presenting an extreme demand scenario. This approach is designed to account for extreme weather that could result in higher demand, while also putting certain generators at higher forced outage rates resulting from impacts to unit performance and/or fuel deliverability. While a consistent approach for operational risk analyses and other approaches for seasonal assessments are currently under development by the Reliability Assessment Subcommittee (RAS), the following examples should be considered for use in NERC's seasonal assessments.

The operational risk analysis can also be used to examine fuel risks to a specific capacity type. The far left bar in Example 1 below includes Anticipated Resources projected available for the upcoming season's peak. It further splits this category into non-gas-fired capacity, dual-fuel capacity, and gas-fired capacity without dual-fuel capability. The second bar from the left shows the net capacity transfers for this area, showing a net import value of approximately 1 GW. The third bar from the left shows At-Risk Capacity based on actual performance data in

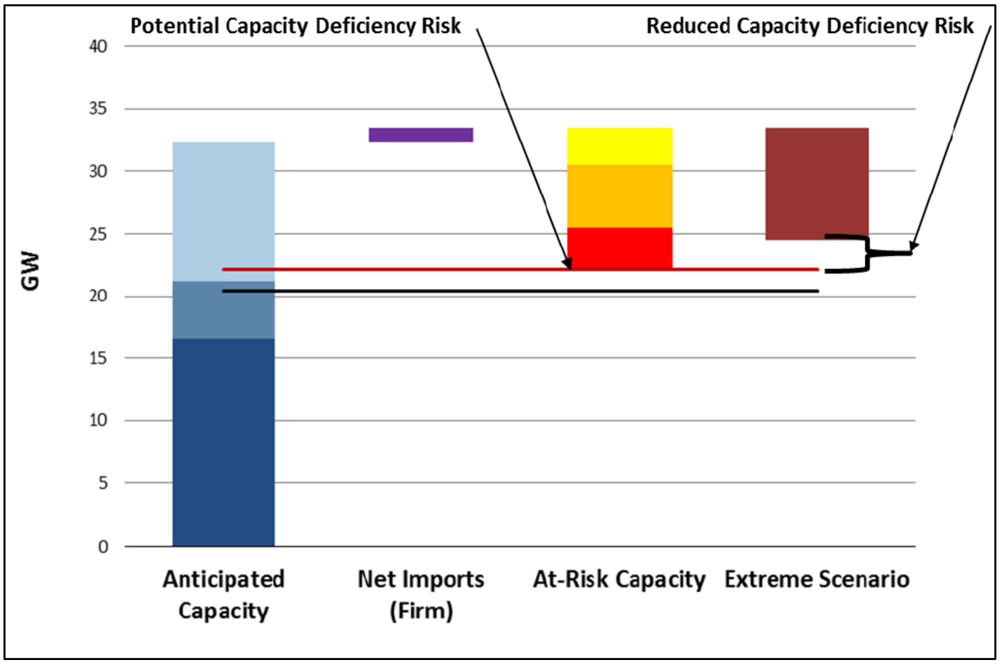
NERC's Generator Availability Data System (GADS). Based on this data, the average forced outage rates can be presented for gas-fired and non-gas-fired outages, as well as the maximum forced outages during an extreme event. Finally, the fourth bar from the left shows a special scenario, examining how much capacity would potentially be impacted by a major gas pipeline disruption. The two lines indicate the 50/50 demand forecast and the extreme demand forecast.

Operational Risk Analysis – Example 1



The figure below further explains how to interpret the results of an operational risks analysis. As the At-Risk Capacity and Extreme Scenario are closer to the extreme or normal demand, the greater the risk for tighter operations with potential resource deficiencies.

Operational Risk Analysis – Interpreting Results



Example of NYISO Summer Assessment

2016 & 2017 Summer Capacity Assessment & Comparison

Line	Item	2016 Baseline Forecast (2016)	2016 90th Percentile Forecast (2016)	2017 Baseline Forecast (2017)	2017 90th Percentile Forecast (2017)
1a	Summer Generation Capacity[1]	38,534	38,534	37,609	37,609
1b	SCR - ICAP Values	1,248	1,248	1,191	1,191
1c	Net Purchases & Sales	2,092	2,092	2,213	2,213
1	**Total Capacity Resources**	**41,874**	**41,874**	**41,013**	**41,013**
2	Assumed Unavailable Capacity (Gen + SCR)[2]	-4,762	-4,762	-4,829	-4,829
3 = 1 + 2	**Net Capacity Resources**	**37,112**	**37,112**	**36,184**	**36,184**
4	Peak Load Forecast	33,360	35,683	33,178	35,488
5	Operating Reserve Requirement	2,620	2,620	2,620	2,620
6 = 4+5	**Total Capacity Requirement**	**35,980**	**38,303**	**35,798**	**38,108**
7 = 3 - 6	**Capacity Margin**[3]	**1,132**	**-1,191**	**386**	**-1,924**

1. Reflects the 2017 Gold Book existing capacity less projected deactivations during the summer of 2017 and known forced outages
2. Derates: 1,418 MW for wind, 561 MW for Hydro, 2,444 MW for thermal units, 56 MW for other renewables and 350 MW for SCRs
3. While the assessment shows a deficiency of 1,924 MW for the 90th percentile load forecast, no involuntary load curtailment is forecast to occur because it is expected that there may be up to 3,083 MW available under Emergency Operating Procedures.

NEW YORK INDEPENDENT SYSTEM OPERATOR

Example of ERCOT Seasonal Analysis

	Forecasted Season Peak Load (May)	Extreme Gen Outages During Peak Maintenance Season (March-April)	Extreme Gen Outages During Peak Maintenance Season (March-April) / Extreme Peak Load (April)
Seasonal Load Adjustment		(8,436)	(293)
Typical May Maintenance Outages	6,147	6,147	6,147
Typical May Forced Outages	3,622	3,622	3,622
Incremental Unit Outages to Reflect April Peak Maintenance Season		8,256	8,256
Total Uses of Reserve Capacity	9,769	9,589	17,732
Capacity Available for Operating Reserves (c-d), MW Less than 2,300 MW indicates risk of EEA1	14,476	14,656	6,513

Special Reliability Assessments

In addition to the long-term and seasonal reliability assessment reports, NERC and the Regions shall also conduct special reliability assessments on a Regional, inter-Regional, and interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or applicable governmental authorities. NERC will coordinate with the Regional Entities to develop and approve special assessment scopes and to determine the necessary data and information required.

Reliability and technical experts from NERC and the Regional Entities may initiate special assessments of key reliability issues and their impacts on the reliability of Regions, subregions, or interconnections (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply and delivery infrastructure, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected bulk power systems in North America.

Special assessments will examine short-term (years 1-2) or long-term (generally years 3 and onward) risks. Special assessments will be developed as a series of issues-driven reports that examine BPS reliability risks over the next 18-24 months. NERC will annually publish these ad-hoc reports as reliability issues are identified. Special assessment scopes will be targeted, timely, and non-cyclical, with in-depth analysis to inform the relevant audience (industry, policy makers, regulators, etc.) and provide insights on ongoing NERC and industry-wide actions to address each topic. The development process for each assessment (i.e., regional coordination, data requests, and analysis) will be adjusted to most effectively address each issue.

NERC should continue to leverage studies and analysis conducted within a Region or Assessment Area. This coordination is critical for the ERO Enterprise model, helps reduce duplicative efforts, and ensures a clear and consistent message on the issue being assessed.

Special Assessment Topic Selection Process

The ERO RAPA maintains a process for identifying and selecting topics to be considered for NERC's special reliability assessments. The process steps are outlined below:

1. NERC staff will develop a list of reliability issues with input from the following:
    a. NERC Executive Management
    b. NERC Operating and Planning Committees (OC/PC)
    c. Regulatory concerns or issues (e.g., State PUC's, FERC, DOE)
    d. Reliability Issues Steering Committee (RISC)
    e. NERC State of Reliability
    f. NERC Long-Term Reliability Assessment
2. NERC staff will present the list of topics with background information to the ERO RAPA on at least a quarterly basis, at which point ERO RAPA will:
    a. Propose additional items to add to the list
    b. Provide additional information on identified issues
3. ERO RAPA will prioritize issues on at least a quarterly-basis
4. NERC staff can initiate formal special assessments on high-priority issues

5. NERC will provide OC, PC and RISC with an opportunity to review the topic selected for assessment.
6. NERC staff will identify necessary participants and develop study framework (e.g. data and information needs)
    a. Data/information collection timelines will vary, depending on the issue being assessed, but will typically be 45 days.
7. NERC staff will develop each study with support from appropriate stakeholders, which could include OC or PC representation (including existing subcommittees, working groups, and task forces). For localized issues, NERC will coordinate closely with the impacted Assessment Area(s) and Region(s) to develop data requests, analysis, and report conclusions. Reports would be presented to the OC and PC for review and endorsement.

The report development process is outlined below: