NERC

Final

Risk Mitigation for Emerging Large Loads

Large Loads Working Group Reliability Guideline

May 2026

RELIABILITY | RESILIENCE | SECURITY

POWERING TODAY. PROTECTING TOMORROW.

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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

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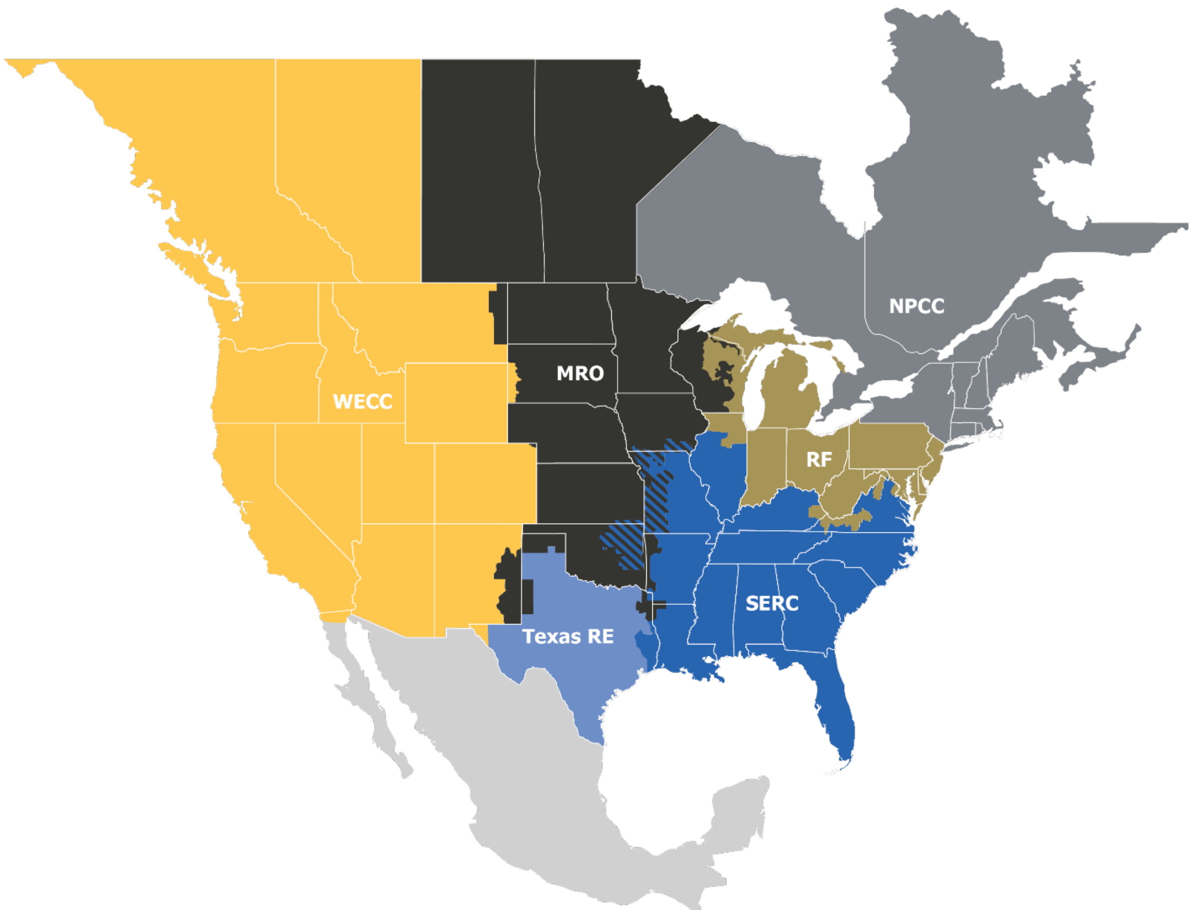
The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices

Executive Summary

Emerging Grid Challenges

Recent developments in emerging large loads and their integration into the BPS have introduced new BPS reliability risks. Some of these risks, like customer-initiated load reduction (CILR) events and large load oscillation events, have been clearly demonstrated and observed. These events can transpire in a matter of seconds, leaving real-time operators little to no time to respond. Additionally, planners anticipate long-term risks related to transmission planning and resource adequacy. While these risks are not yet fully realized, they require proactive planning to mitigate. This reliability guideline details specific risk mitigations recommended for applicable entities to address the risks outlined in prior Large Load Working Group (LLWG) white papers.

These events can transpire in a matter of seconds, leaving real-time operators little or no time to respond.

Ensuring Consistent and Reliable Operations for All Users

This preliminary reliability guideline provides actionable BPS reliability-enhancing guidance for existing NERC registered entities as well as large load entities and their original equipment manufacturers (OEM).

Reliable integration of emerging large loads is not only essential for protecting the BPS but also to accommodate additional large loads faster. When interconnection and operational processes are structured to ensure reliability from the outset, emerging large loads can connect faster and in greater magnitude.

Reliable integration of emerging large loads enables the system to accommodate additional large loads faster.

Guidelines as a Supplement and Bridge to Standards

Although the guidance is voluntary and non-binding, NERC recommends that applicable entities implement the crucial risk mitigating actions and processes offered in this paper. NERC is updating its registry criteria and Reliability Standards to account for the needs associated with large loads, and these guidelines provide key information while the regulatory process moves forward. Implementing these guidelines can lead to enhanced system resilience, reduced outage risks, and more efficient interconnection processes. This guideline will also present future revisions to Reliability Standards. Thus, the guidance in this paper is intended to supplement, rather than replace, any existing or new Reliability Standards. Reliability guidelines are reviewed and updated at least every three years in accordance with the RSTC Charter and may be updated earlier in response to comments or lessons learned.

From Passive Consumption to Active Participation

This guideline recognizes that owners and operators of end-use facilities and equipment were not historically required to be as active in practices and processes that ensure BPS reliability. However, due to the scale and urgency of the risks to BPS reliability, it is strongly recommended that large load entity users of the BPS (if they are not already doing so) participate actively in practices and processes that enhance BPS reliability. Finally, large load entities are encouraged to participate in NERC task forces, webinars, comment periods, and the NERC Standards process to contribute their unique perspectives. The LLWG values the participation of large load entities in its task force and the resulting wholistic work products. Recommended risk mitigations are targeted at existing NERC registered entities as well as large load entities. Large load entities may include large load facility owners and operators. This guidance also extends to OEMs that create equipment used in large load facilities, such as IT equipment, IT cooling infrastructure, and other electronic devices. High-level recommendations with mapping to recommended entities are provided in **Appendix A**.

Introduction

Purpose

This reliability guideline shares initial recommended practices, technical insights, and lessons learned for maintaining BPS reliability while integrating emerging large loads. This guideline will suggest mitigations for risks discussed in the prior LLWG white papers.

Applicability

This reliability guideline is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Resource Planners (RP)
- Large load entities (developers, owners, operators)
- Original Equipment Manufacturers (OEM) for large load facility equipment
- Generator Owners (GO)
- Generator Operators (GOP)
- Reliability and Security Technical Committee (RSTC) subgroups

Background

The first NERC LLWG work item, *White Paper: Characteristics and Risks of Emerging Large Loads*, defines large loads—including data centers, cryptocurrency mining facilities, hydrogen production facilities, manufacturing facilities, and arc furnaces—as "[a]ny commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors." The paper identified key risks from emerging large loads along with the characteristics that can cause those risks. The standards project initiated on March 18, 2026, also includes consideration of the term computational load and computational load entities, which will help further refine this understanding.

The second pending NERC LLWG work item, *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, explains where there are gaps in addressing risks from emerging large loads in existing practices and Reliability Standards. The paper also categorizes risks based on impact and likelihood to recommend actions for mitigation, including Reliability Standards, NERC alerts, and reliability guidelines.

This reliability guideline addresses the second white paper's recommendation to mitigate certain risks with a reliability guideline. This preliminary guideline moves beyond identification of risks and gaps to provide actionable, entity-specific recommendations even as revisions to NERC Rules of Procedure registry criteria and Reliability Standards are underway. It should be read as both a supplement to and a bridge between the white papers and potential future Reliability Standards. Reliability guidelines are just one form of mitigation employed by NERC's Framework to Address Known and Emerging Reliability and Security Risks. Reliability guidelines are "the common approach to use when addressing moderate impact sustained risks that are unlikely, and low impact sustained risks that are unlikely or likely."[1] Reliability guidelines may also be used "to establish performance expectations for emerging risks prior to codifying those expectations into Reliability Standards." This reliability guideline will be used for both purposes: tackling the high-impact high-likelihood risks identified in the LLWG's prior white paper while also addressing moderate- and low-impact risks.

Vocabulary Terms

The reader of this reliability guideline should note that all terms contained in the NERC *Glossary of Terms*[2] and used in this guideline are capitalized. In addition to those terms, some additional terms are defined below. The definitions provided in this paper shall not supersede any future definitions created for the NERC *Glossary of Terms*. Those additional terms in italics are distinguished from those defined and approved by NERC.

NERC Glossary-Defined Terms

Area Control Error (ACE): The instantaneous difference between an entity's Actual Net Interchange (NIA) and Scheduled Net Interchange (NIS), taking into account the effects of Frequency Bias, of correction for meter error, and of Inadvertent Interchange Management (IIM) if operating in the IIM mode. For compliance usage, refer to the term Reporting ACE.

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Area's Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

BES Cyber System Information (BCSI): Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BCSI may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.

Energy Reliability Assessment (ERA): Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Model Validation: The process of comparing simulation results with measurements to assess how closely a model's behavior matches the measured behavior.

[1] NERC, *Framework to Address Known and Emerging Reliability and Security Risks,* February 2021. https://www.nerc.com/globalassets/who-we-are/standing-committees/risc/framework-address-known-emerging-reliabilit-securit--risks_erratta_v1.pdf
[2] NERC, *Glossary of Terms Used in NERC Reliability Standards*, February 2026. https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

Model Verification: The process of confirming that model structure and parameter values represent the equipment or facility design and settings by reviewing equipment or facility design and settings documentation.

Operating Plan: A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company- specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan

Registered Entity: Entities required by law to register with NERC and comply with NERC Reliability Standards.

Terms Defined for This Paper

Many crucial terms used in this paper are not defined formally in the NERC *Glossary of Terms*, but that does not indicate that they necessarily should be added to the glossary. These terms are defined here to help readers in understanding the recommendations offered.

***As-Built*:** The materials, settings, equipment, parameters, and layout of a facility as it was constructed and installed, including any deviations from the original design. This includes all post-commissioning modifications and always represents the current operational state.

***As-Designed*:** The planned parameters and layout of a facility, based on preliminary engineering design prior to construction or installation.

Behind-the-Meter Generation: Generation resources that are connected to the BPS through the same point of interconnection as a load.

Buildout Schedule: The forecasted installed capacity of a large load facility on a monthly, quarterly, or yearly basis.

Cryptocurrency Mining: The process of using IT equipment (e.g., computers, application-specific integrated circuits) to solve mathematical problems to validate and enable various transactions.

Data Center: A physical room, building, or facility that houses IT infrastructure for building, running, and delivering applications and services.

Electrolyzer: A device that uses electricity to split water into hydrogen and oxygen.[3]

Electromagnetic Transient: A power systems domain that considers time-domain instantaneous values rather than phasor domain positive-sequence values for highly detailed analysis.

Large Load: Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces.

Large Load Entity: Any entity that owns, designs, or operates large load facilities.

[3] U.S. Department of Energy, *Hydrogen Production: Electrolysis*, 2024. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

Large Load Operator: An entity that operates a large load facility.

Large Load Owner: An entity that owns or maintains a large load facility.

Phasor Measurement Unit: A time-synchronized measurement device that estimates the magnitude and phase of an electrical phasor quantity like voltage or current.

Point of Interconnection: The location of electrical connection between one system and another (i.e., from a generator or load to the transmission system).

Price Responsive: Behavior of a load facility where demand is dependent, in part or in whole, on energy prices.

Ramp Rate: The rate that a generator or load changes its output or Demand.[4] The units used to describe ramp rate are typically in MW per second or MW per minute.

Site control: The legal authority or permission to occupy, develop, or use a specific parcel of land or property.[5]

Other Terms

This section is used to describe some additional terms in depth. Simply providing definitions for each of the following terms was deemed insufficient.

Co-Location and Colocation

Co-location and colocation are often pronounced the same, but the hyphen generally distinguishes the two terms between a term commonly used in the data center industry and a term commonly used in the utility industry.

Co-location in the utility industry generally refers to two or more facilities sited close to one another. In some circumstances, co-location refers to two or more facilities behind the same point of interconnection.[6] In other circumstances, co-location may refer to many facilities sited in the same general geographic area.

Colocation (also referred to as "colo") in the data center industry refers to "the placement of an organization's own servers and other essential computing hardware for data storage in rented space within a physical data center owned and/or operated by a third party."[7] Colocation may come with increased challenges for the data center owner and operator in predicting demand or other behavior of the end-use equipment.

Customer-Initiated Load Reduction and Load Loss

Historically, load loss has been used to communicate the loss of service to customer load due to an outage in distribution or transmission facilities.[8] The distinction between load loss and customer-initiated load

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[4] Ramp Rate is defined in the NERC *Glossary of Terms*, but it excludes mention of demand changes.

[5] Cobrief, *Site control: Overview, definition, and example*, Cobrief.app, March 2025. https://www.cobrief.app/resources/legal-glossary/site-control-overview-definition-and-example/

[6] NERC, Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants, June 2023. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/irps/reliability_guideline_bess_hybrid_performance_modeling_studies.pdf

[7] Equinix, *What is Colocation?*, June 2023. https://www.equinix.com/what-is-colocation

[8] NERC, *Possible Misunderstandings of the Term 'Load Loss',* March 2021. https://www.nerc.com/globalassets/our-work/reports/white-papers/white_paper_load_loss.pdf

reduction (CILR) is described mainly with regard to residential air conditioners shutting down due to the action taken by controls in each air conditioner that cause the air conditioner to shut down and then restart 10–20 minutes later. In those situations, the air conditioner using control actions to shut down is a CILR. It is also known that adjustable speed drives used in many industrial processes, as well as chillers and air handlers for large commercial buildings, will typically respond to a transmission system fault by shutting down. This occurs even though the fault is very remote from the customer's location and does not cause a loss of service to the customer. Depending on the control system, such as an energy management system used in an industrial facility or commercial property, the equipment may restart automatically after a time delay or may restart only after a human operator takes action. Large customers may switch over to a standby power source automatically even if faults on the BPS are very remote and do not result in an actual loss of service to the facility. Many such facilities perform the automatic switch to BPS-level faults. Customer-owned controls that react to a fault or disturbance on the BPS may prompt a significant amount of CILR; however, these customers do not experience an actual loss of service, and this is not considered a "load loss" in the historical use of the term.

Load loss is formally defined with two terms in the NERC *Glossary of Terms*: Consequential Load Loss and Non-Consequential Load Loss. Both definitions explicitly exclude CILR caused by voltage-sensitive load.

There are multiple causes of CILR, especially for large loads. The first and best-documented cause is voltage-sensitive load that senses a low voltage condition and automatically takes a control or protection action that results in the reduction of demand.[9,10,11,12]

A newly identified driver of CILR involves distributed computing workloads shared across geographically or electrically disparate data centers. When a transmission fault causes a low-voltage condition at a single facility, the interruption of the shared process triggers a synchronized demand reduction across all participating data centers, including those completely unaffected by the fault and low voltage condition. This cause of CILR is not well documented.

[9] NERC, *Incident Review Considering Simultaneous Voltage-Sensitive Load Reductions,* January 2025. https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf

[10] NERC, *Incident Review Voltage-Sensitive Crypto Load Reductions,* January 2026. https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_considering_voltage-sensitive_crypto_load_reductions.pdf

[11] EirGrid and SONI, *Large Demand Facility Fault Ride-Through Issue and Proposed Solutions,* November 2025. https://cms.eirgrid.ie/mpid345-large-demand-facility-fault-ride-through-issue-and-proposed-solutions-eirgrid-and-soni

[12] R. Rabbani, *Large Demand Technical Requirements,* presented at the Grid Code Development Forum, November 2025, pp. 8–21. https://www.neso.energy/calendar/grid-code-development-forum-gcdf-5-november-2025

Chapter 1: Data Collection and Modeling

Data collection is foundational to ensuring reliable integration of large loads into the BPS. This chapter offers many recommended risk mitigations related to data collection, verification, and validation. Additionally, this chapter aims to specify beneficial data collection and sharing activities and processes that will support planning and operational mitigations to effectively and efficiently mitigate risks to BPS reliability.

Collecting data about load facilities helps grid planners and operators make informed decisions about planning and operating the BPS in a way that ensures reliability. Without the proper data to simulate and characterize large loads, grid planners and operators will be unable to accurately model large loads, leading to inaccurate analysis of BPS reliability and uninformed decisions when planning and operating the grid. This means that grid planners and operators need to specify the type, format, and frequency of data submissions required from large load entities across the interconnection, planning, and operations domains.

The second critical component to ensure reliability and mitigate risks after collecting the data to simulate large loads is to share the data with relevant entities. Once the interconnecting entity (i.e., TO or DP) collects data about the end-use facility, it has a duty to share that data with the appropriate entities (e.g., TP, PC, RC, BA, and TOPs) that rely on that data to ensure reliability. This information sharing and coordination activity should be performed as soon as the data is available to share, or as otherwise required by the TPs, PCs, RCs, RPs, BAs, and TOPs. This may include sharing information with neighboring entities to ensure reliability in both systems. Many NERC Reliability Standards already exist for this exact purpose.[13,14,15]

Data Collection Stages

Load interconnection processes and stages often vary from entity to entity. This reliability guideline will break down data collection into three main stages, as shown in **Figure 1.1**, interconnection evaluation, integration and commissioning, and operations. TOs, in coordination with their TPs and PCs, should create timelines associated with data submission requirements that enable studies.

Figure 1.1: Data Collection and Modeling Throughout the Project Lifecycle

The interconnection evaluation stages spans from when the TO or DP first receives the request to interconnect to its facilities until the interconnection agreement is signed. During the interconnection evaluation stages, the load facility may only have a partially complete design. This means initial data submissions are expected to be updated throughout subsequent stages.

The integration and commissioning stage generally starts when the interconnection agreement is signed and ends when the load facility is first energized with grid interconnection. During this stage, the load facility finalizes its design, constructs the load facility, and completes commissioning activities in collaboration with the utility.

The operations stage starts when the load facility when the load facility is first energized with grid interconnection and ends when the facility is fully retired. During operations, TOPs, BAs, and RCs should

[13] FAC-002-4
[14] IRO-010-5
[15] TOP-003-7 and BAL-007-1

receive key operational data on an ongoing basis from large load entities. Additionally, large load entities should provide updated as-built models and data to their TOs, TPs, and PCs following any site modifications, upgrades, or other qualifying changes.

When a large load seeks to connect to the grid, utilities are required to perform a full reliability study per FAC-002 and other relevant assessments, including resource and transmission adequacy assessments. These studies are performed to identify any potential impacts to the transmission system along with any network upgrades that may be required to reliably integrate these large loads into the BPS. Due to the complexity and time required to perform these studies, many utilities may have their own process to conduct the steady-state and transient stability evaluation at various stages of the interconnection process shown in **Figure 1.1**.

Large load entities, TOs, and DPs should collaborate with TPs and PCs through the TO's or DP's interconnection requirements per FAC-001 and MOD-032 to provide all the necessary information required during various stages of the interconnection process. This data should be collected as early as possible with the understanding that the collected data and models may need to be updated throughout the large load facility's lifecycle. This collaboration will ensure the provision of site-specific data necessary for developing accurate models for steady-state and dynamic studies as part of the interconnection requirements. Due to the risk of inaccurate or incomplete data submission, some utilities may require large load entities to prepare and submit the models and supporting documentation for review. Alternatively, other utilities may develop the models themselves by using the information provided by the large load entity. Both approaches have inherent risks: customer-submitted models may lack transparency or independent validation, while utility-developed models could miss critical details if customer data is incomplete. Standardized procedures for model verification, model validation, and attestation of large load data/models are recommended to close this gap.

Utilities should incorporate provisions for ability to gather new information as large load-specific data requirements may evolve. Additionally, large load entities should anticipate evolving data collection requirements throughout the project lifecycle.

Interconnection Evaluation Stage

During the evaluation stage, the large load typically only has access to preliminary design plans and does not complete any construction. This preliminary design data (shown in subsections below) will form the basis of BPS reliability assessments by the interconnecting entity (TO or DP) until design plans are finalized in the next stage and the assessments can be refined with data based on actual procured equipment parameters.

TOs, in coordination with TPs and PCs, should create interconnection request requirements that establish a minimum set of data that must be submitted prior to evaluating interconnection of a large load facility. This minimum data requirement should allow for the large loads to be fully and properly studied per FAC-002. These studies are explained further throughout the rest of the reliability guideline. For any information not available upon initial study, updated information should be provided as it becomes available.

TOs, TPs, and PCs should coordinate and collect the following recommended data for the interconnection study process. In addition, the large load entity that will own and operate the equipment should provide this data to the TOs, TPs, and PCs.

Steady-State Modeling

Steady-state modeling data forms the foundation for transmission planning and interconnection studies. MOD-032 requires some existing registered entities to provide steady-state data to their TPs and PCs according to requirements and reporting procedures developed by the TP and PC.

Large load entities should coordinate with their TOs, TPs, and PCs to provide the following data:

- Requested peak net real power demand, on-site generation plan, and facility expansion plans
  - This includes load facility buildout schedule (MW energized on a monthly/yearly basis)
- Overall large load power factor (value and lead/lag) information for various loading (% rated load) levels
  - The data collection should clearly state where the power factor is specified (medium voltage, high-voltage, point-of-interconnection, etc.)
- Preliminary detailed one-line diagram of all large load equipment (and substation if any) showing network topology, breaker configurations, schematics of their switching arrangements (especially for facilities fed by multiple utility feeders), on-site generators, or battery energy storage system (BESS)
- Reactive devices (STATCOM, switched shunt, etc.) and their associated details (size, number of steps, connected voltage level, etc.)

Dynamic Modeling

Accurate dynamic modeling of large load facilities is crucial to assessing risk. MOD-032 requires some existing registered entities to provide dynamics data to their TPs and PCs according to requirements and reporting procedures developed by the TP and PC. NERC offers some resources to entities to help with accurate dynamic modeling. One such resource is the Load Modeling Working Group (LMWG) Data Center Information Collection Questionnaire, which "help[s] transmission planners identify reliability challenges in the power system and then devise mitigation measures to address them."[16] Additionally, NERC maintains a dynamic modeling guideline to provide clear and more comprehensive recommendations regarding the use of dynamic models for different types of reliability studies.[17] Large load entities should develop and maintain site-specific dynamic models of their facilities. During design and construction of large load facilities, models are considered "as-designed." Large load entities should update their as-designed models to as-built models after construction and any other subsequent qualified change (as defined by the TP and PC) to the facility.

Site-specific as-designed positive-sequence phasor domain (PSPD) dynamic large load models should include considerations for all of the following elements:

- Protection and Control
  - Disclosure of all protection devices and equipment settings
  - OEM test reports (as soon as they are available or updated) that include information necessary for model verification
  - Disconnection and real-power reduction thresholds for voltage and frequency events (levels and duration) at which the components within the large load will disconnect from the utility system or transfer to backup system
  - Reconnection threshold (levels and duration) at which the components within the large load (e.g., IT load, cooling load) will reconnect to the utility system and real-power ramp rates

[16] NERC, *Data Center Information Collection Questionnaire, 2024.* https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/lmwg/data-center-information-collection-questionnaire.pdf
[17] NERC, *Dynamic Modeling Recommendations, 2024.* https://www.nerc.com/globalassets/programs/rapa/dynamic-modeling-recommendations.pdf

- As-designed breakdown of load makeup, including IT equipment, motor load, variable frequency drive (VFD), power electronics, and lighting, including attestation of model parameters that map to load makeup
- Device dynamics
  - Constant voltage, current, or power behavior
  - Active power electronics
  - Reactive devices (STATCOM, switched shunt, etc.)
  - Any hardware or software solutions in the load end to smooth out oscillations

In addition to the site-specific as-designed phasor domain dynamic load models, large load entities should coordinate directly with their OEM to develop and maintain a site-specific as-designed electromagnetic transient (EMT) domain model of their facility. The model may be required by TP and/or PC.

Other Load Data

For adequate risk mitigation, it is recommended that large load entities provide the following data to relevant entities as requested by their TO, TOP, BA, RC, TP, PC, and RP:

- Ramp rate expectations
  - Maximum and minimum ramp rates (startup and shutdown)
  - Any cyclical demand ramps and their associated frequencies (especially in the sub-synchronous frequency range)
- To the best extent feasible, expected sub-hourly demand profiles should be collected
- Disclosure of large load facility demand being connected with other large load facilities connecting through alternate POIs (example: multiple disparate data centers used for the same training process where an interruption at one data center causes demand changes for all the connected data centers)
- Load make up/usage information, such as portion of AI training load in data center loads
  - Multi-tenant data center businesses (or other data centers with multiple types of workloads) should include the worst-case variability of all tenants combined.
  - Changes to this information are crucial to supply to the utility and may affect grid reliability.
- Harmonics
  - Expected current and voltage harmonic injection spectrum from the facility and aggregated at point of connection (details noted in **Chapter 6**)
- Other
  - Backup generators or BESS not disclosed through the regular generator interconnection process
    - A description of the use cases of the on-site generator or BESS
    - How long can the load operate disconnected from the utility with the on-site resource
  - Type of large load (computational, industrial, etc.) or data center and its expected operations (e.g., AI training, cryptocurrency mining, traditional cloud, electric arc furnaces, oil and gas load facilities)

Integration and Commissioning Stage

During the integration stage, the large load entity finalizes the load facility design and performs construction. During this stage, the large load entity should be providing verified as-built data to the interconnecting entity (TO or DP). In turn, the TO should share the data updates with TPs, PCs, and other relevant entities. Sharing the latest updated data is especially important for data like dynamic models.

TOs, TPs, PCs, TOPs, BAs, and RCs should coordinate and collect the data recommended in the following sub-sections during the integration and commissioning stage.

Updates to Modeling Data

As mentioned previously, steady-state, dynamics, and short-circuit modeling data forms the foundation for transmission planning and interconnection studies. MOD-032 requires some existing registered entities to provide this data to their TPs and PCs according to requirements and reporting procedures developed by the TP and PC. It is recommended that large load entities update their modeling data and provide those updates to their TO, TP, and PC throughout the construction and finalization of the large load facility. When the facility is finalized and nearing commissioning, the large load entity should update its models to as-built models.

Additionally, at this stage, large load entities should perform model verification. More details on model verification processes are given at the end of the chapter.

Monitoring Equipment

To facilitate the reliable operation of the BPS, large load facilities need high-speed monitoring devices installed at the high side of the main power transformer. Crucial high-speed recording devices should be capable of measuring triggered fault recording (FR), continuous dynamic disturbance recording (DDR), and sequence of events recording (SER) data. FR and DDR recording data should be measured, at least, at the high-side main power transformer and should meet specifications for sampling rate, recording window, and triggers, similar to those in PRC-002 and PRC-028.[18,19] The SER recording device(s) should also meet specifications similar to those in PRC-002 and PRC-028. The requirements for offline data storage capabilities and retention should be determined by the TP and PC.

The combined detection capabilities of the FR and DDR devices should be adequate for the following uses:

- Dynamic model validation (see end of this chapter) and performance evaluation
- Event analysis (see **Chapter 4**)
- Oscillation detection and analysis (see **Chapter 5**)

Additionally, TOs should ensure that sufficient power quality monitoring is installed prior to commissioning. More details are provided in **Chapter 6**.

Other Load Data

All data mentioned in the prior "Other Load Data" section should be updated up to and after commissioning. Changes to this information are crucial to supply to the utility and may affect grid reliability.

[18] PRC-002-5
[19] PRC-028-1

Operations Stage

The operations stage is defined by ongoing coordination and data sharing between the large load entity, TO, TOP, TP, PC, BA, and RC. This stage is broken into two main categories: ongoing data sharing (e.g., telemetry of equipment statuses and measured values, disturbance monitoring and reporting) and data updates (e.g., new dynamic model, additional load). Per FAC-002, qualified changes to the large load facility must be studied. In addition, FAC-002 states that PCs must maintain a publicly available definition of qualified change. It is strongly recommended that PCs include any changes to demand over a determined threshold or dynamic model performance in their definition of qualified change. Updating data that was provided in prior stages is crucial to ensuring ongoing reliable operations of the BPS. However, the operations stage involves ongoing event- and time-based data collection, coordination activities, and real-time monitoring. Together, these activities support reliable operation and planning of the BPS.

Large load entities should provide and TOs and DPs should collect and share with relevant entities (TOP, TP, PC, BA, RC, and other entities responsible for forecasting, dispatching, and real-time operations) at least the following:

- Data Updates
  - Any updates for as-built facility information, including all prior mentioned steady state, dynamics, and short circuit data
  - All necessary information (defined by the BA, TOPs, and RCs) to conduct real-time analyses and assessments (TOP-003 and IRO-010) to address the potential risks due to large load ramping, disconnection, and reconnection to the grid
  - Expected load profiles, equipment specifications, ramp rates, load forecasts, real-time telemetry, event data, and logs following grid disturbances, backup generation, and demand response
  - Updated models whenever qualified changes are made to the facility
- Ongoing Data Sharing
  - Coordinate with the TO, TOP, BA, and RC to provide real-time measurements of key electrical quantities (real power, reactive power, and voltage) of each large load facility (if not already monitored by TO)
  - Near-Term Data Sharing
    - Day-ahead operating plan and indicative plan for near-term demand (7–10 days)[20]
    - Outage scheduling information
- Post-Event Data Sharing
  - Share all required event data with relevant entities (mentioned above and in **Chapter 4**) upon request within a time period determined by the TP and PC (example: 90 days of request)

Dynamic Model Assessment, Verification, and Validation

Accurate dynamic models of large load facilities are required to understand reliability implications and potential mitigations. The inaccurate modeling of large loads can be mitigated by verifying the models and modeling information at various stages of the interconnection process, followed by validation processes during and after commissioning processes.

[20] While it is acknowledged that large load entities cannot always perfectly forecast demand, forecasts based on historical data and other operational data to which the large load entity has access will help mitigate risks from large load variability.

Large load entities, in coordination with the OEMs of the facility equipment, should create and maintain validated as-left models so that grid planners and operators can make informed decisions regarding BPS operations. Therefore, large load entities should supply (and TOs and DPs should require) accurate, verified, and updated data at various stages (e.g., as-designed, as-built, and as-left) of the planning, integration, and ongoing operations stages of the project lifecycle, including any material updates to equipment that would impact modeling or settings.

Each TO, in coordination with its TP and PC, should implement the following processes throughout their data collection processes:

- Model Quality Assessment
  - Model quality assessment that includes "evaluating the plausibility, usability, and numeric stability of a model based on a review of model documentation, data, and simulations"[21]
- Model Verification Process
  - Model verification requirements may include benchmarking PSPD models against EMT models of the facility.
  - Large load entities should maintain and share dynamic models that accurately represent the installed equipment and parameters, including performing model verification and providing the model verification report to relevant entities (TPs and PCs) prior to energizing.
  - Large load entities should provide attestation that the as-built model parameters represent the installed equipment rather than default parameters that don't represent the specific facility.
- Model Validation and Performance Analysis
  - Develop Event Data Collection Processes:
    - Large load entities, in coordination with their TOs and DPs, should install high-resolution FR and DDR capable devices for large loads.
    - Recording devices should possess detection capabilities for at-risk oscillation frequencies with offline data storage capabilities and retention as determined by TP and PC.
  - Establish Model Validation and Post-Event Analysis Process:
    - TPs and PCs should develop a process for post-event data sharing and analysis, involving large load entities, TPs, TOPs, BAs, and RCs, to validate the large load's performance and model accuracy based on the collected measurement data.
  - Establish Process for Model Updates and Re-Study:
    - TPs and PCs should establish a process for large load models to be updated given model validation and post-event analysis data.
    - TPs and PCs should also establish criteria for model updates and what qualified changes require a re-study.

[21] IEEE, "IEEE Approved Draft Recommended Practice for Test and Verification Procedures for Inverter-based Resources Interconnecting with Bulk Power Systems," in IEEE P2800.2/D4.1, November 2025. https://ieeexplore.ieee.org/document/11261433

Chapter 2: Interconnection Studies and Processes

TPs and PCs should establish a comprehensive interconnection process and periodic near-term system-wide study process using steady-state, dynamic, and short-circuit models to assess the reliability impacts of large loads. TPs and PCs should coordinate with TOs and DPs in their areas to collect data needed for the interconnection process.

TOs, in coordination with TOPs, BA, TPs, PCs, and RCs, should establish and publish a comprehensive, consistent interconnection process that includes the following:

- A method for collecting, at a minimum, the data required in **Chapter 1**
- A definition of readiness criteria and an evaluation of any new interconnection application against the readiness criteria before continuing in the interconnection process
- Interconnection study agreement and associated process
- Interconnection studies using steady-state, dynamic (PSPD and EMT if needed), and short-circuit models to assess reliability impacts of large loads
- A periodic process in the near term that studies the collective impact of all large loads in a region defined by the PC that energize in a common time frame using steady-state and dynamic models
- A comprehensive commissioning process that ensures operational readiness for large loads, as detailed in **Chapter 4**
- Consideration of potential impacts to underfrequency load shed (UFLS) and undervoltage load shed (UVLS) plans, as detailed in **Chapter 8**

Interconnection Studies

TPs and PCs should incorporate at least the following in their large load interconnection study processes in order to ensure that the reliability impact is adequately studied:

- Steady-state studies based on the as-designed data provided by large loads to the TOs and updated as necessary, based on design, upgrades, or other qualifying changes
- Transient dynamic analyses that consider the following:
  - The large load facility on-fault and post-disturbance frequency and voltage recovery behavior
  - The collective impact of electrically close facilities
  - The total potential magnitude of load loss considering the individual and collective tripping or customer-initiated load reduction of large loads during system disturbances
- Transmission protection and control coordination studies that include the following:
  - Recommendations to TOs regarding any transmission protection coordination changes to transmission relays or modifications to large load fault interruption devices to ensure reliable isolation of system faults
  - Recommendation on changes to protection and control settings of local protective devices
  - Recommendations on changes to operation, protection, and control settings of the large loads to minimize customer-initiated load reduction during system disturbances
  - TOs, TOPs, and large load entities should coordinate and study any potential configurations with a risk of a customer's equipment impacting flows on the BPS (outside of when the large load is

served radially) so that power is not transported to another part of the system through the customer's equipment

- Inclusion of large load entity input into the TO coordination of protection and control devices to identify how the large load can assist in the reliable isolation of system faults

- TPs and PCs should create a process to determine when it is necessary to conduct small-signal, sub-synchronous, and transient stability assessments
- TPs and PCs should develop EMT screening criteria where needed[22] (e.g., for sub-synchronous interaction); each of the following may be used as EMT screening criteria, subject to the discretion of the TP and PC:
  - When PSPD simulations do not converge or do not demonstrate the reliability concerns of interest
  - Large power electronic devices
    - Including HVdc lines, large electric arc furnaces, inverter-based resources (IBR), or static reactive power devices
  - Weak grid conditions
    - In the context of converter-driven stability, this may correspond to a short-circuit ratio of two or less,[23] as defined by the three-phase bus fault current available from the system and the total apparent power rating of the power electronics on site
  - Series capacitors
  - Large steam, gas, or hydroelectric turbine generators
    - These are of particular concern if the load profile has significant fluctuations in the five to 60 Hz range

Triggers for Re-Study

Similar to the existing Reliability Standard FAC-002, TPs and PCs should create and publish criteria that trigger a re-study of the large load facility. Experts in the ERCOT region state that some large load facilities have changed from a data center to a cryptocurrency mining facility after receiving approval of their interconnection request application. Late-stage modifications like this would almost certainly require a new dynamic study. This scenario is clear, but less-clear scenarios should also be examined in the PC's re-study criteria.

TOs and DPs should have clear policies for handling significant changes in load characteristics that occur after the initial interconnection studies. Large load facility characteristics may vary significantly with design decisions made during the interconnection process (e.g., the selection of specific vendors for electronic devices or determination of the site's mix of computational processes). These changes may introduce stability-related risks that were not identified in the initial studies as the result of the mismatch between prior and current load model data. This could necessitate technical mitigations (e.g., system upgrades or devices such as energy storage or reactive power support) that require significant cost and lead time to install. If these mitigations cannot be put in place by the original energization date, it may be necessary to delay energization or restrict the load's operational range until the mitigations are in place. For almost any

[22] Screening criteria specific to large loads are not yet widely established. Traditional EMT screening criteria for oscillation-related reliability issues associated with power electronics may be considered.

[23] A short-circuit ratio of two or less is offered as an example, not as final guidance. Additionally, other types of short-circuit ratio may be more appropriate as screening criteria.

facility, some differences between as-designed and as-built models are inevitable, and these policies should provide reasonable accommodation for changes in load characteristics that do not significantly alter the reliability risks associated with the load interconnection. TOs, DPs, and load owners all face cost, schedule, and reliability risks when major changes to interconnection scope occur. Therefore, they should collaborate to identify and prioritize specific model data and design decisions that are most crucial for accurate BPS reliability assessments as early as possible.

Chapter 3: Long-Term Planning and Resource Adequacy

The incorporation of new large load interconnection requests into reliability assessments is not only vital to accurate studies of the BPS but also needed to ensure that future transmission design is adequately modeled. Inadequate modeling of large load interconnections poses risks to BPS planning by potentially leading to incorrect study results and incorrect long-term planning assumptions.

A primary risk to BPS reliability from large loads in the long-term planning and resource adequacy domains is insufficient transmission and generation caused by under-forecasting demand.

Regardless of whether large load studies are performed in a cluster or serially, TPs and PCs should coordinate with TOs to establish study processes to ensure that large load facilities interconnected to the BPS are adequately studied.

Analysis for Transmission Planning

The sudden and uncoordinated loss of a large load could cause overvoltage and overfrequency conditions that trigger protective relays that lead to a cascading outage, and the highly variable nature of some large loads' demand profile can induce risks outside of the traditional peak and off-peak scenarios studied in transmission planning analysis. Therefore, when conducting analysis for transmission planning studies, TPs should modify their study assumptions to capture the risks that large loads pose due to their size and operational behaviors.

To mitigate the risks posed by the sudden loss or rapid reduction of a large load, the loss of the large load should be studied as a contingency in both steady-state and dynamic assessments by the TP and PC. Similarly, the TP and PC should study credible loss of large loads clusters (all in close electrical proximity to a single fault or disturbance) and provide that information to the RP, BA, and TOP.

Planning processes should analyze various loading scenarios representing a diversity of load demand and generation patterns as appropriate for their areas in both steady-state and dynamic assessments. The dynamic assessment should include voltage stability and frequency stability assessments as documented in **Chapter 5**.

Interregional Coordination Between Grid Planners

If a TP or PC studies and approves a project, such as an addition of a transmission line, that project can significantly impact the neighboring entities depending upon the size and location of the project. Therefore, TPs and PCs should coordinate with neighboring entities to account for such projects, whereby the models, the contingencies, and the study results are shared with the neighboring entities to help them perform their own studies.

Large loads interconnecting at the seam/boundary with a neighboring entity could have significant reliability impacts on that entity. Therefore, it is important for the RCs, TPs, and PCs to establish the processes for sharing pertinent information and data of the large load facility, such as load size, type, dynamic model data, and protection settings, with the neighboring entity at the interconnection stage. This allows the neighboring entity to perform its own studies whether independently or in collaboration with the incumbent entity. Moreover, there should be processes for the entities to share the results of reliability studies where any reliability issues are found at the neighboring entities' facilities. This would facilitate identifying system upgrades to mitigate such reliability issues.

Resource Adequacy Analysis

Given that large loads frequently seek connection to the grid faster than transmission and some forms of generation can be built and due to the size of these large loads, they can pose risks to resource adequacy as documented in the NERC LLWG *White Paper: Characteristics and Risks of Emerging Large Loads* section on Resource Adequacy.

Simulation of Delayed Generation Interconnections

Demand may outstrip generation supply as large loads are added faster than the addition of generation resources. Many large loads are expected to require firm service, limiting their ability to be considered flexible or providing limited demand-response capabilities. This directly impacts BPS reliability through the reduction of BA Operating Reserves. To address this, RPs should model scenarios in their evaluation of resource adequacy, such as delayed generation additions, before incorporating large load additions.

RPs should coordinate with load-serving entities, TOs, DPs, and TP/PCs to identify the expected large load growth to incorporate in their studies, consistent with state, provincial, and federal regulatory requirements. The load growth may include a buildout schedule that occurs over the course of months to years. These buildout schedules should be considered in studies. An example would be a facility that increases the amount of load each month, quarter, or year as construction is completed. The modeling criteria may consider "tiers" of load additions, like the generator tier levels of the *Long-Term Reliability Assessment* (LTRA),[24] to demonstrate the quantity and timing of large load additions based upon confidence levels for those values. RPs can use this information to understand the level of risk associated with the timing of large load additions coupled with timing of generation additions.

Without the ability to model the timing and likelihood of new large load additions and new generation resources, RPs could miss key inputs to resource adequacy studies. These missed inputs could lead to inaccurate resource plans or the underestimation of the risks associated with those plans.

Simulate Operational Constraints and Flexibility of Large Loads

The risk to resource adequacy from the lack of representation of large loads' operational flexibility and constraints is discussed in the NERC LLWG *White Paper: Characteristics and Risks of Emerging Large Loads*[25] and *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*. NERC's *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment*[26] (NERC Energy Reliability Assessment Working Group) echoes this by emphasizing the need for accurate modeling of demand response and non-conventional load behavior.

Large loads introduce complexities (operational constraints, partial controllability, or internal energy assets) that traditional resource adequacy models can fail to capture. Large load operating schedules, driven by an array of different processes, can limit load flexibility and controllability. Co-located generation and storage can make these loads appear firm where in reality, they may switch between grid supply and on-site resources, creating unpredictable net demand patterns. They can have rapid ramp rates (up or down), operational constraints, and behind-the-meter (BTM) generation or storage that traditional models do not capture. If operational characteristics are not represented in resource adequacy models and flexibility

[24] NERC, *Long-Term Reliability Assessment*, January 2026. https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
[25] NERC, *White Paper: Characteristics and Risks of Emerging Large Loads*, July 2025. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf
[26] NERC, *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment*, December 2024. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/erawg/technical-reference-document-considerations-for-performing-an-era-v2.pdf

assessment, planners may overestimate available flexibility or underestimate load variability—leading to misaligned resource procurement and reliability events during peak demand, large loads switching on and off, or large loads transferring to co-located and/or BTM generation.

While traditional RA frameworks typically assume static or predictable load profiles, failure to represent the constraints and operational characteristics of large loads (including interactions with BTM generation and/or storage) can lead to underestimating load variability or overestimating system flexibility, leading to misaligned resource procurement and increase in loss of load risk during peak demand periods, periods when large loads switch on and off, or those when large loads transfer from the grid to on-site co-located generation and vice-versa.

RPs should update their planning processes and resource adequacy models to include realistic assumptions about operational constraints and flexibility of large loads. They should follow NERC's ERA guidance to model demand-side variability, including time-coupled constraints and state-dependent behaviors. The updated models should be able to capture dispatch constraints (e.g., minimum runtimes, startup/shutdown behavior), separate firm vs. flexible load components, time-varying operating limits (e.g., AI training window), and characteristics of the BTM resources (e.g., solar power plants, BESS, backup gensets) and should consider whether it is appropriate to run sensitivity analysis under various scenarios (e.g., no load flexibility, partial or full demand response availability, fast ramping events).

Large load entities should provide documentation—as required and requested by the RPs—of expected dispatchability, ramp rates, internal generation/storage characteristics, technical constraints, and operating limits (e.g., IT workload cycles, min/max uptime). This mitigation ensures that load behavior is realistically modeled, preventing false assumptions about demand-side flexibility. Additionally, this mitigation improves the accuracy of load/resource balance forecasts, enhances planners' ability to predict and prepare for realistic worst-case conditions, and better aligns planning decisions with actual load behavior.

This mitigation enables planners to do the following:

- Accurately size reserve margins
- Procure fast-ramping resources or demand-response capacity only when needed
- Avoid unexpected load inflexibility that could lead to loss-of-load events

Mitigation is sufficient when the following conditions are met:

- Flexibility is modeled using real operational bounds
- The models explicitly represent load controllability attributes
- The models distinguish between firm and interruptible demand
- Assumptions are vetted with large load entities using data from actual load tests or validated technical documents
- Sensitivity scenarios evaluate adequacy across different flexibility levels, if appropriate (e.g., if load is fully interruptible vs. firm)

It is important to note that most resource planning models evaluate adequacy across an integrated hourly (or minute) time frame. Some large loads may exhibit high intra-minute volatility across normal operations that would need to be considered for appropriate balancing availability, like fast ramping resources. Large load entities should share this information with RPs. RPs should consider methods to ensure sufficient resource adequacy and capabilities to support the unique characteristics and behavior of large loads, including intra-minute volatility.

This action is critically important. Inadequate modeling of large loads' behavior and flexibility can result in resource shortfalls during the tightest periods, compromising BPS reliability.

Simulate Transmission and Fuel Supply Constraints in Loss of Load Expectation Analysis

The NERC LLWG's *White Paper: Characteristics and Risks of Emerging Large Loads* and *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Load* discuss the need to include transmission system constraints and locational risk in resource adequacy assessments. The first white paper discusses the locational nature of reliability risks and the second white paper identifies gaps in modeling transmission constraints in resource adequacy studies. The NERC *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment* emphasizes the importance of modeling transmission-limited zones, deliverability, and non-firm transfers.

Large loads can be highly concentrated in specific locations and can shift locational demand profiles. They tend to cluster geographically near favorable conditions (e.g., low-cost power, substations), which may not have sufficient local generation or transmission. If loss of load expectation and Planning Reserve Margin studies do not incorporate local transmission constraints, they may miss localized capacity risks, especially during high load and outage scenarios, resulting in undetected reliability gaps.

Ignoring transmission limits in loss of load expectation modeling can result in the following:

- Underestimating zonal load-serving risk
- Hiding bottlenecks that delay energy delivery
- Generating overconfidence in system-wide adequacy

TPs, PCs, and RCs should coordinate with RPs to integrate transmission delivery limitations, if any, into loss of load expectation assessments. RPs may consider using network-aware ERA models as described in the NERC ERA *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment*, including tools that support zonal reliability assessment, stochastic unavailability, and delivered load margin metrics.

TPs should provide current and planned constraints (e.g., congestion zones), transfer capabilities under normal and contingency scenarios (N-1, N-1-1), and weather-resilient infrastructure gap transfer capability curves for the relevant planning horizon. TPs and PCs should consider any transmission constraints associated with long-term transmission and generation outage work in both peak and off-peak seasons.

To the extent that emerging large loads have high load factors across the day, an increase in large loads may drive incremental reliance on specific fuel types, increasing vulnerability to common-mode fuel supply disruptions. RPs, PCs, and RCs should assess fuel supply and common-mode dependency risk by coordinating with gas system operators where applicable to assess cross-sector dependency risk. These assessments should be reflected in Planning Reserve Margin evaluations and resource procurement decisions.

Large load entities should provide accurate siting and expansion timelines to inform demand forecasts and expected reliability requirements. They should identify location, monthly or yearly buildout schedule, and reliability expectations (e.g., firm vs. interruptible interconnection) and share anticipated transmission service type (e.g., firm vs. non-firm).

This mitigation is complete under the following conditions:

- Resource adequacy simulations reflect forecasted transmission-related generation deliverability limitations (for example, transmission outages and congestion risk)
- The models reflect correlated outages (e.g., N-1-1 or weather-related) that can co-occur with large load peaks
- The assessment output identifies locational loss of load risk even in regions with high overall reserve margins
- The assessment output identifies locational loss of load risk in regions where zonal constraints exist

The importance of this mitigation is critical, and without location-aware analysis, risks may remain hidden in high-growth load pockets even when overall system adequacy appears sufficient. Without this, systems may appear resource adequate but fail under real-world locational stress.

Simulate Multiple Metrics for Resource Adequacy Assessments

Emerging large loads increase variability and systemic uncertainty, which can amplify loss-of-load events and increase exposure to low-probability, but high-impact, reliability risks.

As discussed in NERC's LLWG *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, while resource adequacy planning traditionally focuses on ensuring sufficient generating capacity and reserves to meet expected demand using metrics like loss of load expectation and Planning Reserve Margin, it may not fully account for impactful combinations of large load peak consumption hours and resource outages. As a result, some dimensions of reliability risk—such as event duration, magnitude, and severity—may not be consistently reflected in current assessments. This missed information may lead to underestimation of system risk and underinvestment in flexible resources or infrastructure.

To mitigate reliability risk, RPs, where appropriate, should consider using the following:

- Multiple probabilistic metrics, consistent with existing NERC ERA guidance, to characterize different dimensions of reliability risks, such as loss of load hours, expected unserved energy, and conditional value at risk. These metrics provide information on the duration, magnitude, and severity of potential shortfall events.
- Probabilistic tools that support thousands of integrated weather, load, and generation scenarios and quantify reliability outcomes using scenario probabilities, rather than relying on a set of average or representative conditions. This can improve visibility in conditions where large load peak demand coincides with resource outages or extreme weather events.

RPs should use results to determine any need for additional mitigation such as flexible resources or increased reserve margins, if needed.

To support multiple probabilistic metrics, the large load entities should provide information on anticipated load profiles, operating characteristics, and expected behavior under normal and extreme events, such as granular load shape data, flexibility and curtailment capabilities, emergency response protocols, and modeled stress-event behavior (e.g., when tripped or derated). Where applicable, large load entities should also provide information on expected availability and operational constraints of on-site and BTM resources.

The mitigation may be considered sufficient when the following is true:

- Studies produce multiple probabilistic adequacy metrics across multiple scenarios
- Metrics are validated, where appropriate, through comparison with historical events or stress-testing under extreme but plausible system conditions

The importance of this action is critical. This enables an understanding of reliability risk under uncertainty introduced by emerging large loads. Without expanded metrics, RPs risk being surprised by rare, severe outages that aggregate metrics like loss of load expectation cannot detect.

Chapter 4: Operations and Balancing

In the operations horizon, system operators are responsible for ensuring that the BPS is reliable and secure. This includes ensuring that load and generation are balanced, which is required to maintain stability. This chapter covers recommendations for entities to ensure reliable operations of the BPS via risk mitigations in commissioning processes, real-time operations, and balancing.

Commissioning Process

In power systems engineering, commissioning is typically the process used to bridge from a planned facility interconnection to real-time operations. Commissioning can include data verification activities, additional studies, and physical preparations of the site to enable successful and reliable BPS operations.

TOs in coordination with RCs, BAs, TOPs, and TPs should establish a comprehensive commissioning process that ensures operational readiness for large loads. Additionally, it may be appropriate to perform some commissioning tests again as new parts of the facility are energized, considering that many large loads have a tiered buildout schedule that can last months to years.

Commissioning processes established by the abovementioned entities should include the following:

- Verification of communications including, but not limited to the following:
  - Real-time large load entity contact for operational communications
  - Installation and testing that live telemetry such as supervisory control and data acquisition (SCADA) and phasor measurement unit (PMU) are sending and receiving as intended
  - If participating in demand response, testing of demand-response signals and successful deployment of demand response
  - Verify demand-response capability consistent with BA and TOP requirements for inclusion in Emergency Operating procedures
- Prior to energization of the large load facility, ensure that the loads are properly accounted for in load forecasting and other operational modeling, like outage coordination and day-ahead studies
- TOs, RCs, and BAs, in coordination with large load entities, should conduct commissioning tests of the large load during interconnection and test the load facility's ramp ability and max consumption
- Should require the large load facility to be studied in a near-term operational planning assessment, in coordination with the TP, PC, TOP, and RC, that includes all large load facilities nearing their energization date
- Should require comprehensive dynamic model verification process prior to energization
- Should require comprehensive dynamic model validation process to verify the large loads performance during and after commissioning
- After energization, if end-user facilities seek to make qualified changes, appropriate studies and commissioning processes should be performed
- Large loads should validate design and performance criteria in the interconnection requirements after energization and during commercial operation
- Ongoing post-commissioning testing and verification between TOP, BA, RC, and large load entity for large load facility configurations, settings, communications, and personnel contacts

As the maximum consumption of a large load facility may increase over time, some requirements of the commissioning process may need to be repeated when the maximum consumption is increased or a significant change to the facility occurs.

Real-Time Monitoring

To support real-time operational functions like short-term forecasting, balancing, and event analysis, entities mentioned in **Chapter 1** should collect real-time and post-event data as needed to support analysis and other processes that ensure reliability.

Short-Term Forecasting

While "short term" is not explicitly defined, throughout this chapter short term is generally defined to mean anywhere from one hour to seven days, depending on the specific context. Some large loads, including computational loads, pose new challenges for short-term operational forecasting by RCs, BAs, and TOPs. Some of these loads can be highly variable and exhibit both second-to-second and minute-to-minute power oscillations along with fast ramping capabilities. If large loads are not considered in short-term forecasting, the BA could under-commit generation in real time, potentially leading to reliability issues and load shedding.

Load forecasting information from large loads is critically important for BAs to assess risks to energy adequacy under BAL-007 and to ensure appropriate unit commitment and dispatch. TOPs in consultation with BAs should establish required large load forecasting information needs and timing of updates. The large load entity may need to provide near-term hourly net-load forecasts and planned outages to ensure sufficient load forecasting.

Load Coordination in Demand-Response Programs

DPs and TOs should consider whether it is appropriate to register large loads in demand-response programs if the large load is willing to participate and can be flexible. This will allow for the load to be managed as needed to address operational conditions. The TOP, RC, and BA should require large loads to submit their current operating plans that provide a forecast for the next seven days to align with BAL-007 Near-Term Energy Reliability Assessments. Without participation in demand-response programs or the submission of current operating plans, the system operator will find it challenging to properly account for large loads in their forecasts and thus energy and ancillary service procurement and operational planning.

Operational Analysis of Load Behavior

The best source of a short-term forecast would be directly from the entity that controls the demand of the large load facility. The large load entity should provide, and the BA and RC should require the large load entity to provide, near-term demand forecasts and Operating Plans as well as real-time telemetry.

Once the large load has become commercial, the TOP, RC, and BA should review the large load's normal operational behavior to assess how it matches against their forecasted load consumption predictions.

TOPs, RCs, and BAs should monitor large loads and observe their load usage patterns to inform short-term forecasting. This will allow them to understand current and past behaviors for forecasting models.

Balancing and Reserves

To ensure the reliability of the BPS, the BA must ensure that load and generation are constantly balanced. Given the ability of large loads to ramp hundreds of MWs in seconds as documented in *White Paper: Characteristics and Risks of Emerging Large Loads*, this poses a challenge for BAs to maintain the load and generation balance given the highly variable load profiles. Failure to maintain this balance could lead to increased risk to the frequency stability of the BPS.

Balancing Reserve Management

Large loads that operate with limited grid visibility, no coordination with BAs, and no ride-through obligations can lead to system imbalance. Abrupt load changes or disconnections lead to system imbalance, unanticipated ACE swings, regulation reserve exhaustion, and frequency instability, especially during disturbances. Large, fast-varying loads can rapidly swing demand by tens or hundreds of MW within seconds or minutes. These swings strain balancing reserves and frequency control, especially if BAs lack telemetry or coordination with the load operators.

BAs should consider incorporating large load variability in assessments to aid in maintaining sufficient regulating capability and coordination to handle these demand swings while staying within CPS1 and BAAL limits. This reduces the chance that an unpredictable 500 MW load surge or drop will result in ACE excursions that jeopardize frequency stability or violate reliability criteria. In essence, the BA should "bring the large loads into the loop" of frequency control (either by securing more responsive resources or by working with the load operator to smooth out changes), thereby maintaining balance and compliant performance. Requiring granular telemetry and data for large loads closes the visibility gap that currently exists.

Large load entities, in coordination with their TOs, BAs, and RCs, should perform the following risk mitigations:

- Coordinate with the TO to provide real-time measurements of key electrical quantities (real power, reactive power, and voltage) of each large load facility (if not already monitored by TO as mentioned in **Chapter 1**)
- Provide near-term demand forecast from as little as five minutes in advance to as much as seven days in advance (as mentioned in **Chapter 1**), including advance notice of substantial load changes (e.g., planned step changes)
- Register points of contact
    - Assign operational contacts at the large load facility for 24/7 grid coordination with TOP, BA, and RC

BAs, in coordination with TOPs and RCs, should perform the following risk mitigations:

- Specify any interconnections design requirements to TOs in their footprint for inclusion in the TO's interconnection requirements (FAC-001) to maintain grid reliability, such as operational ramping limits, interconnection/integration process requirements, communication protocols, and monitoring equipment
- BAs, TOPs, and RCs should each specify any data requirements to large loads necessary to perform operational and real-time analysis and monitoring, such as models and load forecasting
- Identify any "large loads" in their area (e.g., above a MW threshold and/or high ramp rate) and incorporate their expected behavior into operations; examples include the following:
    - Adjusting AGC parameters or supplemental regulation reserves to cover large load demand fluctuations
    - Establishing coordination protocols with the load or its serving entity to manage or mitigate sudden demand changes

- When performing unit commitment and reserve considerations, prepare to handle the largest expected decrease in demand due to large load ramping, customer-initiated load reduction, load loss as a contingency, and TPL-001[27] contingencies that could cause loss of one or more large loads (these may require coordination with TPs and PCs along with dynamic simulations)
- Incorporate load volatility in reserve planning by adjusting regulating and contingency reserve needs using scenario analysis that reflects large load variability
- Require large load curtailment participation by establishing programs for voluntary or automated demand modulation from large loads during regulation scarcity

TOPs should do the following:

- Enable situational awareness by using EMS displays or tools to show large load status and ramp rates
- Coordinate events with BAs by notifying BAs of any unplanned load deviations or outages

In absence of these mitigations, system operators will lack real-time insight into the most volatile loads on the system, directly compromising frequency control, reserve deployment, and reliability metrics like ACE.

Large Load Ramping and Effect on Area Control Error

Large loads with highly variable demand profiles can present challenges in controlling the ACE, as their demand can be difficult to forecast even hours or minutes in advance. Additionally, as mentioned in the **Customer-Initiated Load Reduction and Load Loss** section, transmission faults that lead to CILR can result in large amount of rapid demand reduction. If left unmitigated, these deviations can result in system-wide reliability issues, such as frequency excursions and eventually cascading outages. As the first step to successfully manage ACE in real time, BAs should obtain the necessary information from large loads to support BA analysis functions, real-time monitoring, and near-term energy reliability assessments (e.g., TOP-003 and BAL-007).

Mitigating the Impact on ACE from Load Variability

Large loads can introduce significant variability and fluctuations on a second-to-second, minute-to-minute, and hourly basis. The frequency and magnitude of these fluctuations can put significant strain on a BA to successfully manage ACE.

The ability of a BA to manage potential fluctuations of large loads is dependent on corrective actions at its disposal, considering factors such as the following:

- AGC dispatch time intervals
- Units available for frequency regulation/AGC
- Operating Reserves available

Furthermore, most current BAL standard metrics focus on performance across 30-minute intervals or greater, which may not account for performance risks associated with highly variable ACE deviations on an intra-minute basis. If these risks are not mitigated, it puts the burden not only on the interconnected BA but on the entire interconnection.

[27] TPL-001-5

The traditional dispatch hierarchy of a) unit commitment ensuring that adequate supply is available to meet projected needs, b) dispatch being utilized to follow load and inter-tie transactions at defined intervals, and c) frequency regulation leveraged to manage intra-dispatch variability may be inadequate to manage projected variability from large loads.

Risk mitigations to manage impacts of variability include the following:

- Large load entities should minimize variability via large load facility software mitigations, large load facility hardware mitigations[28]
- TOs should consult with and incorporate any BA-specified requirements necessary to maintain ACE and reliability into their interconnection requirements[29]

Mitigating the Impact on ACE from Customer-Initiated Load Reduction

High amounts of load reduction or loss for a single contingency or event can present significant challenges to BAs in maintaining ACE if scheduled regulating-down frequency regulation service is insufficient. Compounding this challenge is that large loads may self-isolate from the grid for minutes or hours before reconnecting. If the BA is forced to decommit generation to maintain ACE for the initial load loss, there may be insufficient dispatchable generation on-line or regulating-up frequency regulation service to maintain ACE when the large loads reconnect or ramp up to return to their normal or expected consumption levels.

Therefore, BAs in coordination with their TOs, TPs, and PCs, similar to generation most-severe single contingency (MSSC) requirements in BAL-002 and BAL-003, should identify and incorporate their most severe load contingency for loads into their unit commitment and reserve considerations. The development of a most-severe load contingency should consider CILR events as well as other traditional contingencies. Importantly, this relies on the TP and PC obtaining accurate dynamic load models of large load facilities and their low-voltage ride-through behavior.

TOs should, in consultation with BAs, establish operating protocols with large loads that document expected behavior of large loads when reconnecting or ramping back up to expected load levels.

Real-Time Operations and Coordination

Large loads can impact real-time operations in various ways that need to be coordinated. As described in *White Paper: Characteristics and Risks of Emerging Large Loads*, a reliability concern is that some large loads are interconnecting to the grid for the first time within the near-term transmission planning horizon (five years). To mitigate this, TOs should establish requirements as described in the following sections in their interconnection agreements prior to energizing for the first time to ensure reliable coordination between large loads and system operators. This coordination should be completed using similar processes for generators and/or transmission being energized and connected for the first time.

Voltage Control and Coordination for Point of Interconnection

TOs, TPs, and PCs should coordinate to establish allowable power factor ranges for the large load point of interconnection as well as establishing allowable reactive power and voltage controls (e.g., sub-transient, transient, steady-state) for the large load.

[28] E. Choukse et al., *Power Stabilization for AI Training Datacenters*, arXiv.org, August 2025. https://arxiv.org/html/2508.14318

[29] At a minimum, this should include the establishment of operational load ramp rate limits (e.g., MW/min) for large loads in normal and post-disturbance scenarios

Outage Coordination Process Updates Incorporating Load

For established large loads, the outage coordination reliability requirements are needed to ensure that near-term assessments and real-time operations are evaluated properly. This is consistent with IRO-017 to maintain an outage coordination process for generation and transmission. Importantly, TOs and DPs should coordinate with large load entities to report forced and planned outages of large load facilities to relevant grid operators (TOPs, BAs, and RCs) in a timely fashion (as determined by the TOP, BA, and RC). RCs should establish operating protocols that include process(es) for coordinating planned outages consistent with IRO-017 for generators and transmission.

Analysis of Customer-Initiated Load Reductions in Real-Time Contingency Analysis

TOPs and RCs should incorporate steady-state contingencies representing customer-initiated load reduction events into real-time contingency analysis (RTCA) and in operations studies. If it is found that a customer-initiated load reduction event of one or more large loads could occur for a contingency, then the RTCA contingency list should be updated accordingly to reflect the behavior of the large loads without having to run online dynamic analysis in real-time.

Large Load Communication Requirements

Large loads can impact the reliability of the BPS if their real-time operations are not aligned with the operational criteria defined by the RC, BA, and TOP. This includes ramp rate limits, real-time dispatchability, providing day-ahead schedules, and data sharing. Similar to a generator, unexpected operations by a large load may raise concerns about balancing reserves and maintaining system reliability within system operating limits.

As mentioned in *Assessment of Gaps in Existing Practices, Requirements and Reliability Standards for Emerging Large Loads*, large loads are not registered entities at the time of this guideline's initial publication and are not obligated to establish real-time communication with utility operators. The following recommended actions will help align large load entity responsibilities with those of existing registered entities, ensuring a coordinated response during critical events and improving overall system reliability.

Establish Interpersonal Communication Capabilities

Require large loads to develop and maintain interpersonal communication capabilities that are essential for maintaining system reliability. This would be similar to the requirements set forth in COM-001 for GOPs. By implementing this requirement, large loads would be better equipped to communicate effectively with system operators, reducing the potential for miscommunications during critical situations.

Training and Adherence to Operating Instructions

Large load operators should undergo training and adhere to Operating Instructions akin to the standards outlined in PER-005 and COM-002 for GOPs. This would ensure that large load entities are well-prepared to respond appropriately during emergencies, thereby enhancing operational efficiency and safety.

Response to Operating Instructions

Require operators of large loads to respond promptly and effectively to Operating Instructions issued by RCs, BAs, and TOPs as outlined in TOP-001 and IRO-001.

Event Analysis Process Changes

During normal grid operations, it is expected that the BPS will experience faults leading to disturbances and protection system operations. After such an event, the TO will typically conduct a review to analyze how the system performed to ensure that the BPS operated within its design criteria. With the increasing deployment of large loads, this event analysis process should be updated.

Additionally, large loads, as part of interconnection requirements, should provide all necessary information needed for TPs, PCs, BAs, TOPs, and RCs to conduct post-event analyses and assessments.

TOs and TOPs should coordinate with large load entities to have a monitoring system in place to ensure that the most up-to-date data is provided to BAs and RCs and other interested parties.

The following processes are recommended to help mitigate the risks associated with collecting data for event analysis:

- Develop tools and applications to identify abnormalities and root causes, trigger alarms and send notifications, display events, and create event reports
- Develop monitoring strategy in coordination with large load entities for monitoring large load facilities and incorporate corresponding requirements in TO’s interconnection requirements and/or TOP’s operating agreement documents
- Develop pre-energization and ongoing event validation processes/procedures:
  - Identify monitoring locations and develop a monitoring system to support real-time situational awareness and quick event data retrieving, including power quality monitor data, relay fault data, sequence of events, and phasor measurement unit recordings
  - Pre-energization validation to ensure the TOP is capable of monitoring the large load as designed in its real-time control center before it is declared ready for operation per applicable requirements/agreement
  - Ongoing event validation to help assess control setting performance per the large load facility design criteria, which may be performed on a periodic basis (as applicable)

Chapter 5: Stability

As outlined in the first LLWG white paper, large loads can significantly impact the stability of the BPS. As stated in **Chapter 2**, TPs and PCs should perform required steady-state and dynamic studies under FAC-002 using the best available models provided by the large loads to identify the impacts and coordinate with the large loads to mitigate any risks pertaining to the BPS.

Major reliability risks may remain hidden when large loads are not accurately represented in these studies, leading to unforeseen stability issues, such as the unexpected widespread tripping of large loads because of a nearby fault. Additional consideration should be given to stability studies for large loads sited with BTM generation. As mentioned in **Chapter 1**, TOs and DPs, in coordination with TPs and PCs, should create interconnection request requirements that establish a minimum set of data and milestones that must be achieved prior to energizing a new large load facility (or qualified changes, as is relevant). This minimum data requirement should allow for the large loads to be fully and properly studied per FAC-002. The dynamic models provided by large load entities should accurately demonstrate, at a minimum, the characteristics mentioned in **Chapter 1**.

Voltage and Frequency Disturbance Performance

Some large loads, like data centers and cryptocurrency mining facilities, are voltage sensitive and there are documented incidents of large loads unexpectedly reducing demand from the utility supply during and after normally cleared faults.[30,31,32] CILR in small quantities may not adversely impact BPS reliability, but at certain megawatt thresholds, CILR can cause cascading outages on a time scale of cycles to seconds. The acceptable CILR threshold depends on local and interconnection-wide factors like system strength and inertia.[33,34] Thus, studying CILR events is a crucial part of ensuring reliable BPS operations. Large loads have not demonstrated similar sensitivity to frequency excursions.

To study the impact of large load disturbance performance on grid reliability, large load entities should provide accurate dynamic models that demonstrate frequency and voltage facility-level disturbance performance (e.g., tripping, switchover, reductions, reconnection) to the TO, TP, and PC. The term "trip" refers to disconnection from the grid either due to the action of a protection device or due to switchover to an alternate source of energy like a battery in the large load facility uninterruptible power supply (UPS). TOs should update their interconnection agreements to require that this data be provided. For existing facilities, TOs should obtain voltage and frequency disturbance performance settings from large load facility owners that are verified via documentation from the OEM-provided operation manual of the equipment inside the facility. TOs should coordinate with new and existing large load entities to communicate disturbance performance requirements for their areas. Large load entities should consider operational procedure changes and firmware upgrades, among other things, to ensure that their new and existing facilities can meet the disturbance performance requirements defined by the TO, TP, PC, BA, and RC.

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[30] NERC, *Incident Review Considering Simultaneous Voltage-Sensitive Load Reductions,* January 2025. https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf

[31] A. Springer, *Large Loads in ERCOT – Observations and Risks to Reliability*, presented at the Large Loads Task Force Kickoff Meeting, October 2024, pp. 20–54. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_kickoff_presentations.pdf

[32] NERC, *Incident Review Voltage-Sensitive Crypto Load Reductions,* January 2026. https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_considering_voltage-sensitive_crypto_load_reductions.pdf

[33] L. Hinojosa, *Load Loss Threshold Analysis*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, May 2025. https://www.ercot.com/files/docs/2025/05/19/Large_Load_Loss_Analysis_051625_LLWG.pptx

[34] J. Billo, *Large Electronic Load (LEL) Voltage Ride-Through Overview*, presented at the ERCOT Large Load Workshop, June 2025, pp. 1–18. https://www.ercot.com/files/docs/2025/06/13/COMBINED_June-2025-Large-Load-Workshop.pptx

If the disturbance performance model is not available for an as-built design of an existing large load facility, the TOs and TPs should require, and large load entities should provide, an updated disturbance performance model that accurately demonstrates the real behavior of the large load facility. Additionally, models for new and existing large load facilities should meet relevant model quality tests established by the TPs and PCs.

TOs, TPs, PCs, BAs, and RCs should coordinate to determine local and system-wide thresholds for the magnitude of rapid demand change their area can withstand without violating frequency or voltage stability limits. They should use the results of these studies to inform the need for establishing minimum voltage and frequency disturbance performance requirements including: rate-of-change of frequency (RoCoF) ride-through requirements, phase-jump considerations, low-voltage ride-through, high-voltage ride-through, or transmission mitigations to reduce system risk specific to their region in the interconnection requirements. TOs, in consultation with BAs, RCs, and TOPs, should establish these requirements for large loads considering the similar requirements for generating resources (e.g., PRC-019, PRC-024 and PRC-029). Ride-through requirements should be established on a per-interconnection basis to ensure that system-wide needs are met while avoiding mismatched ride-through performance and protection/automated transfer settings. Additionally, the frequency ride-through may not trip zone should be coordinated with UFLS trip settings.

In addition to disturbance performance criteria, if TPs determine that an uncontrolled load disconnection poses a risk to system stability, the TO, TP, PC, and RC should take actions to protect the reliability of the BPS. This could include imposing demand limits on large loads (i.e., establishing large load curtailment as a System Operating Limit),[35] installing dynamic reactive devices that can either prevent voltage sags from affecting the facility or prevent over-voltages resulting from sudden loss of the large load facility, or making other system changes as needed, such as having the BAs commit fast downward responsive resources that can manage the system overfrequency resulting from sudden load disconnection.

Large load entities should design their facility, including equipment protection and control settings, to accommodate the disturbance performance requirements in the interconnection requirements and coordinate with TPs and PCs on voltage and frequency ride-through settings.

While establishing disturbance performance criteria for large load facilities, generator overfrequency limits should be considered to avoid cascading generator tripping. PRC-024 requires GOs to set their generator frequency protective relaying such that the relaying scheme does not trip the generator within the “no trip zone” of PRC-024 Attachment 1 with some exceptions. Attachment 1 requires continuous operation if the system frequency is less than 60.5 Hz for the Eastern Interconnection and 60.6 Hz for all other Interconnections. Outside of the continuous operation zone, there is a timeline associated with when generators may trip. For example, in the Western Interconnection, generators may trip after three minutes of the grid frequency remaining over 60.6 Hz. As a result, operators should aim to arrest the frequency zenith to less than 60.6 Hz for CILR events. ERCOT has set its official overfrequency limit at 60.4 Hz in the transient time frame, [36] citing that not all generators can withstand a frequency of 60.6 Hz. GOs should assess the capability of their generator equipment and facility-level protection to withstand the upper frequency limits and should inform BAs, TOs, TPs, PCs, and RCs of their equipment limits so they can be considered in large load ride-through analysis as required by R3 of PRC-024. Additionally, all GOs should assess the capability of their facilities and protections to ride-through the high RoCoF conditions that may occur during CILR events.

TOs, in coordination with TPs, PCs, RCs, and BAs, should create requirements for large loads co-located with generators (connected through the same point of interconnection) to coordinate disturbance performance.

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[35] J. Billo, *Large Load Voltage Ride-Through Related Studies,* presented at the ERCOT Large Load Working Group (LLWG) Meeting, August 2026. https://www.ercot.com/calendar/08142025-LLWG-Meeting

[36] L. Hinojosa, *Load Loss Threshold Analysis*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, May 2025. https://www.ercot.com/files/docs/2025/05/19/Large_Load_Loss_Analysis_051625_LLWG.pptx

Additional consideration should be given to the fact that many existing IBR facilities are already subject to PRC-029 which specifies ride-through criteria for IBRs (and PRC-024 for synchronous machines). Subsequently, GOs, large load entities, and TPs and PCs should coordinate disturbance performance between co-located generators and large load facilities (connected through the same point of interconnection).

Voltage Stability

Voltage instability caused by large loads can result in low- or high-voltage conditions, increased reactive power demand, and potential voltage collapse. To mitigate these risks, a structured approach across the planning, interconnection, and operational domains should be adopted. TOs should require large load entities to submit voltage ride-through curves, reactive power capabilities, and UPS/tap-changer control settings as part of the interconnection package and ongoing data updates. This will facilitate the appropriate simulation of voltage recovery behavior under disturbances.

TPs and PCs should incorporate PSPD and EMT (if appropriate) dynamic models that adequately represent voltage-sensitive protections and controls. This allows evaluation of short- and long-term voltage recovery and dynamic reactive requirements. For large load facilities, utilities should consider their net load shapes (in case they have BTM generation) and the use of on-load tap changers (OLTC) at large load facilities to assess their impact on long-term voltage stability. Long-term voltage stability analyses are performed using the classic P-V/Q-V analyses in power flow domain. For large load facilities, one should consider their net load shape to identify the loading levels during peak load conditions (where voltage stability issues generally appear). Additional studies may be needed for off-peak conditions where voltage instability may occur. Studies should also consider if any BTM or co-located generation is available to mitigate the voltage issues. Where necessary, TPs should assess the potential need for dynamic reactive support such as static VAR devices or synchronous condensers.

TPs and PCs should run contingency-based voltage assessments that include realistic load trip/reconnect behaviors, evaluating system VAR margins and identifying locations where rapid voltage recovery is not possible. TOs should coordinate with RCs and TOPs to define restoration sequences that avoid simultaneous reconnection of large blocks of load. Real-time alarms should be configured to detect declining voltage stability margins (e.g., low-Q reserve). Voltage-related event analysis should include comparison of observed large load behavior to modeled expectations, with models adjusted accordingly. Post-event findings should inform ongoing model improvements and settings refinements.

TPs and PCs should also assess voltage stability, including under/over-voltage performance, the potential need for under/over-voltage protection schemes, and the impact of CILR events (as discussed in **Customer-Initiated Load Reduction and Load Loss**).

These voltage stability mitigation practices should be reflected in the interconnection agreement and assumptions should be updated periodically with operational data and commissioning results.

Frequency Stability (Overfrequency)

Rapid changes in real power demand, including large load reductions or ramping, may introduce frequency disturbances and instability. The most consequential and credible mechanism observed to date is aggregate CILR following transmission faults. These events create a nearly instantaneous imbalance where generation exceeds demand by the amount of CILR. The large imbalance of generation and load drives system frequency upward at a rate determined by the magnitude of load reduction, the interconnection’s online inertia, and primary frequency response. The largest RoCoF would be observed when interconnection inertia and available primary frequency response are at minimums. The three primary variables involved in this problem are largest aggregate CILR, online inertia, and frequency-responsive reserves.

The first variable to consider when analyzing overfrequency risk is the largest aggregate CILR. The largest aggregate CILR is dependent on the location of the fault, the amount of nearby voltage-sensitive load, generator fault contribution, and system topology. Accurate dynamic models of the loads in the area are crucial, including load voltage dependence for stall and forced reduction. The risk is higher in areas where generator fault contribution is lower, and more voltage-sensitive loads are in close proximity. All these factors should be considered when determining and simulating the largest aggregate CILR contingency. With accurate dynamic models of the system, generators, and the large load facilities, all these factors should be demonstrated. To accurately simulate the largest aggregate CILR, TOs should collect, and large load entities should provide, detailed information on voltage conditions and timing that will cause large load facilities on their system to reduce output or disconnect from the grid. This is commonly referred to as low-voltage and high-voltage ride-through characteristics. As mentioned in **Chapter 1**, TOs should collect, and large load entities should provide, dynamic models that accurately represent behavior from all devices that affect facility-level disturbance performance such as the UPS transfer logic and backup generator synchronization, which should be modeled and validated in dynamic simulation studies (e.g., via PSPD or EMT tools). This should include delay logic, reconnection criteria, and voltage/frequency tolerance ranges. TOs should share the collected dynamic modeling information with their TP and PC. This dynamic model should go through model verification and model validation processes, as mentioned in **Chapter 1**.

On an ongoing basis, TPs should use large load facility dynamic model information to assess and report to their BA the largest credible CILR due to a worst-case fault on their system. TPs should also plan the system in such a way that the largest credible load reduction is limited to a level that is acceptable for the BA and PC regions in which they operate.

The second variable of frequency stability for CILR events is the amount of on-line inertia, which is variable and depends on what synchronous generators are on-line. CILR events that happen when inertia is lowest will have the highest RoCoF, though overfrequency risk may be highest when inertia is low and downward reserves are low. BAs and RCs should account for the expected amount of on-line inertia when procuring Operating Reserves that will adequately ensure reliability given the worst case CILR event.

The third variable of frequency stability for CILR events is the amount of on-line frequency-responsive reserves. These reserves are comprised of on-line generation with legroom (generally defined as real power generation minus minimum real power capability of the unit) that has been tested and verified to be capable of providing downward droop response as described in the *Primary Frequency Control Reliability Guideline*.[37] Resources capable of providing fast frequency response will also have a major effect on the arresting of overfrequency conditions.

To mitigate the risk posed to frequency stability, PCs in each Interconnection should analyze and study the worst-case scenario(s) where the system is shown to have at- or near-minimum inertia and primary frequency-responsive reserves. The analysis should include the worst-case fault(s), analyze system frequency stability, and identify any generators that may trip off-line. The findings of these frequency stability studies should be shared with BAs so that they may make more informed decisions during unit commitment and reserves coordination.

[37] NERC, *Primary Frequency Control Reliability Guideline,* September 2023. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/rs/primary_frequency_control_reliability_guideline_v_4.0_clean_v3---dr.pdf

Through a combination of the aforementioned risk mitigations to frequency stability risks, interconnection frequency should remain stable and not infringe on any overfrequency limits that may impact reliable BPS operations (cascading generator trips). If the system frequency is shown to be stable in simulation and in practice for worst-case or near worst-case scenarios, the risk is deemed to be mitigated.

Oscillation Mitigation

Certain large loads with variable and cyclical profiles, such as AI data centers and electric arc furnaces, can introduce forced oscillations into the BPS. These loads often operate cyclically. If the frequency of load cycling is in the electromechanical range (i.e., 0.1–2 Hz for inter-area and local modes), there is a potential for interacting with natural low frequencies and causing widespread forced oscillations.[38] Such oscillations pose significant risks to the BPS and should be studied before these loads are energized.

Additionally, other complex dynamic control interactions have been demonstrated to cause oscillations, including one cryptocurrency mining facility in ERCOT[39] and one data center in Dominion. For oscillations at higher frequencies, risks of subsynchronous control interactions (SSCI) or subsynchronous torsional interactions (SSTI) exist. These risks need special consideration in studies and monitoring, especially for large loads co-located with generators.

TOs should consider incorporating monitoring and mitigation provisions in interconnection agreements to address potential oscillatory behavior. TOs and RCs should revise their oscillation monitoring and mitigation platforms and procedures to account for potential load-induced oscillations. If wide-area oscillations are observed, coordinated actions by multiple RCs may be needed to address the reliability concern. RCs should incorporate large load-specific actions in their coordination plans. Adverse reliability impacts from oscillations that occur may be mitigated through coordinated use of supplemental controls.

Additionally, TOs, TPs, PCs, and RCs should collaborate to establish requirements for large loads to avoid exciting specific modes of the local system and interconnection.

Cyclical power demand from large load facilities can significantly impact the stability of electric grids. In order to properly study the effects of cyclical demand, the high-speed FR and DDR data mentioned in **Chapter 1** should be collected. This fluctuating demand has the potential to excite torsional modes in nearby generators, leading to mechanical stress and potential damage. It can also interfere with the natural modes of other equipment, such as the controls of IBRs. Additionally, large load facilities should be assessed for their potential to contribute to oscillatory instability. This can occur under certain grid conditions if device controls in large load facilities interact unfavorably with the network impedance or other nearby equipment, potentially leading to underdamped, growing, or sustained power oscillations.

As these system interactions can cause significant risk to the local transmission system, generators, and the entire interconnection, the TO should also incorporate monitoring and protective equipment requirements for large loads as required by the TOP and RC. Large load entities should also incorporate monitoring and protective equipment that allows them to validate that the large load facility meets the TO's performance requirements. Some specifications for the types of devices required are given in **Chapter 1**. TPs, PCs, and large load entities should consider the following recommendations to identify mitigation and reduce potential risks associated with oscillation.

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[38] NERC, *Eastern Interconnection Oscillation Disturbance Forced Oscillation Event,* January 2019. https://www.nerc.com/globalassets/our-work/reports/event-reports/january_11_oscillation_event_report.pdf

[39] P. Gravois, *Large Load Oscillation Event*, presented at the ERCOT Large Flexible Load Task Force (LFLTF) Meeting, March 2025. https://www.ercot.com/calendar/08142025-LLWG-Meeting

To support both proactive and post-event mitigation, the following practices are recommended:

- **Detection and Mitigation:**
  - As mentioned in **Chapter 1**, high-speed recording devices should measure data at the large load facility.
  - Data from these monitoring devices should be incorporated into existing oscillation detection and source identification platforms that the TOs and RCs are using. TOs should determine the appropriate monitoring equipment to accurately capture the desired frequency content.
  - TPs and PCs should proactively gather data to gain an understanding of what the load pattern would be like both in terms of amplitude and frequency content.
  - In the operations time frame, if the TO, TOP, or RC detects low-damping conditions for a natural mode, they can consider establishing mechanisms to request large loads to defer oscillatory behavior as long as the low-damping conditions persist.
  - Large load entities owning and operating AI training data centers, as directed by TOs, TPs, PCs, and RCs, should implement necessary mitigations to meet oscillation damping metrics and thresholds including software mitigations, GPU power smoothing, and rack-level energy storage.[40]
- **Interconnection Processes:**
  - TPs and PCs should provide expected system strength ranges at the POI for equipment validation.
  - TPs and PCs should establish oscillation attenuation metrics and real power amplitude variation thresholds that loads must meet under interconnection requirements. They should also establish limits (amplitude and frequency) on oscillatory demand from large load facilities depending on the risk of subsynchronous resonance (SSR) or exciting any inter-area and local modes. Approaches range from facility-specific requirements to system-wide requirements.[41] An empirical rule that may be followed is avoiding natural frequencies excitable from a large load location. These frequencies and high-risk locations may be identified through planning studies.[42]
  - TPs and PCs should study interconnections in weak grid areas or locations and identify mitigation if needed. To support this requirement, additional criteria beyond SCR should be considered. For a load co-located with a generator, there is no clear guidance on whether the SCR should be calculated based on load rating, generator rating, or net load rating.
- **Monitoring Requirements**:
  - High-resolution monitoring as detailed in **Chapter 1** and **Chapter 4** can support real-time oscillation detection and post-disturbance verification of load behavior. Additionally, grid operators should identify load facilities that are contributing to oscillations, informing mitigation actions that could include isolating the source load. Accurate characterization of frequency signals above 5 Hz may require point-on-wave measurements.[43] Exact sample rates, technology

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[40] E. Choukse *et al.*, *Power Stabilization for AI Training Datacenters,* arXiv.org, August 2025. https://arxiv.org/abs/2508.14318
[41] ERCOT, *Large Electronic Load Sub-Synchronous Oscillation (LEL-SSO) Power Variation Challenges and Discussion*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, January 2026. https://www.ercot.com/calendar/01222026-LLWG-Meeting
[42] S. Biswas, A. Varghese, K. Chatterjee, et al. *Evaluating the Risk to Bulk Power System Reliability from Large Load Induced Oscillations*, TechRxiv. November 2025, doi: https://doi.org/10.36227/techrxiv.175623878.87007943/v2
[43] J. Follum *et al., Phasors or Waveforms: Considerations for Choosing Measurements to Match Your Application,* April 2021. https://www.naspi.org/sites/default/files/reference_documents/pnnl_31215_follum_phasors_waveforms.pdf

types, and post-processing needs may depend on the specific phenomena being analyzed and monitored.

- Data from these monitoring devices should be incorporated into existing oscillation detection and source identification platforms that the TOs and RCs are using.

- **Event Analysis and Model Validation:**
  - If a TO or TOP determines that a large load facility is contributing to system oscillations, the TP and PC should conduct post-event analysis using as-built models to assess damping behavior and determine if any equipment will need to be installed to mitigate the oscillation.
  - Time-synchronized PMU, POW, and SCADA data should be analyzed to compare observed response with simulation expectations. Model adjustments should follow as needed.
  - Where oscillatory behavior is observed, TOs and RCs may consider protective relaying schemes or disconnection logic as part of a broader effort to safeguard grid stability.

Angular Stability

Angular instability may arise in systems with significant CILR events or rapid real power demand fluctuations, particularly during faults in weak or constrained areas. While this risk is often less emphasized than voltage or frequency stability, under certain network conditions, it may result in inter-area angle swings or loss of synchronism. GOs should consider when to implement out-of-step relaying at key interfaces to detect and isolate unstable swings promptly. See **Figure 5.1** demonstrating loss of synchronism in a PSPD simulation.

Recent industry experience highlights a specific angular stability concern involving large loads co-located with generation in areas with weak transmission connectivity.[44] In such scenarios, the sudden loss of load can leave nearby generators without sufficient transmission capacity to evacuate power to the broader grid, leading to large angle swings or potential loss of synchronism. This condition is particularly pronounced when both the generation and load are part of a combined facility with limited ties to the rest of the system.

[44] M. Peterson, "Data Center Interconnection Studies & Challenges," presented at the Large Loads Task Force Meeting and Workshop, Apr. 2025, pp. 53–65. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_april_meeting__technical_workshop_presentations_.pdf

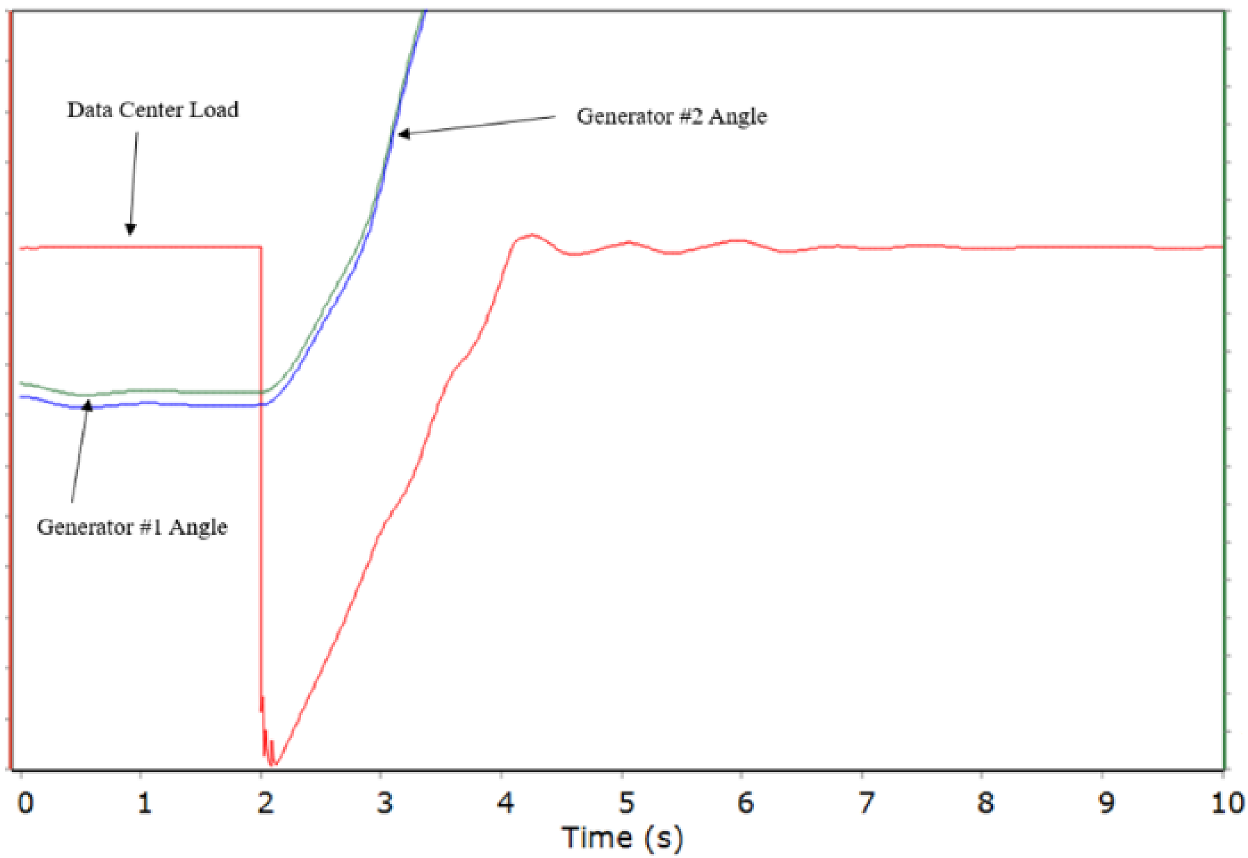

Figure 5.1: Multiple Generators Lose Synchronism Following a Data Center Load Trip and Subsequent Rapid Recovery

TOs and PCs should consider angular stability risks when evaluating large loads in areas with long radial lines or high impedance corridors or during scenarios involving delayed fault clearing. EMT or RMS simulation models should represent the fast dynamics of load components, including converter controls, UPS synchronization, and backup generation transitions. This is necessary to assess system response to disturbances. For large load centers, planners should study the impact of large load trip or recovery during N-1 and N-1-1 contingencies, especially in low-inertia regions. This helps determine the risk of angular separation or uncontrolled power swings.

Event analysis post-fault should examine angle trajectories and coherency groups to determine if large load behavior was a contributing factor to any loss of synchronism or instability. TOs and PCs should utilize real-time monitoring to monitor for angular stability risks. TOs and TPs should update modeling assumptions accordingly based on system changes and identified control or stability issues.

Chapter 6: Power Quality

Emerging large loads often contain significant quantities of electronic power supplies, adjustable speed drives, and rectifiers, which can generate harmonic distortion and voltage fluctuations in the BPS. TPs should perform studies using the as-designed models provided by the large loads to identify power quality impacts and ensure that they are within the acceptable levels or if any mitigation measures will be necessary. Studies should be conducted under the diverse operating modes of large loads while also considering various potential load equipment configurations.

Harmonics

When considering harmonics, power quality standards (e.g., IEEE Standard 519-2022) already exist that specify harmonic limits with which all large loads are recommended to follow. Since existing power quality standards are not mandatory, TOs or DPs should include harmonic limits in their interconnection requirements for large loads, as well as any RC, BA, or TOP requirements specific to their footprint, into their interconnection requirements under FAC-001.

Using the data provided by the large load, the TP and PC should use as-designed models to ensure that individual and overall current harmonics injections into the interconnecting substation are within the limits.

During the power quality studies, harmonic evaluation studies may be performed by the TP and/or PC to do the following:

- Determine the impact of large load-produced harmonic current injections on electrically close synchronous generators and other equipment to ensure that the levels are within the specified equipment ratings (i.e., permissible continuous equivalent negative-sequence current capability)
- Consider evaluating risks of harmonic resonance and determine the potential impact of large load-produced harmonic current injections on existing harmonic filter banks (i.e., impact of harmonics on individual filter component ratings)
- Determine the impact of large load-produced harmonic current injections on the overall voltage distortion at the interconnecting substation
- Determine the harmonic spectrum of the large load under various grid conditions, including low short-circuit ratio (SCR) scenarios
- Determine if mitigation measures will be necessary to meet the machine or harmonic filter ratings. In cases where technical solutions are insufficient for meeting harmonic limits, alternative approaches like utility-scale battery storage may be needed

To support the analyses above, load owners should provide the current harmonic spectra to the TP enabling estimation of the individual harmonic current injections (up to 100th harmonic order)[45] at the interconnecting substation.

Managing Facility Design Changes that Impact Power Quality

The harmonic emissions and voltage fluctuations associated with a particular large load may vary significantly with design decisions that may not be made until the interconnection process is well underway (e.g., the selection of specific vendors for electronic devices or determination of the site's mix of computational processes). In such cases, the load facility design changes may impact the load facilities' compliance with power quality requirements. TOs and DPs should have a clear process on how and when large load facility design changes are communicated to them by the large load entity. In these situations, the

[45] The 100th harmonic order is provided as example guidance, and entities may modify this for their own applications.

large load entity may experience cost increases and schedule delays if TO and DP processes are unclear on how design changes are communicated and handled. If design changes result in 10% or more increase in projected harmonic emissions,[46] interconnection studies should be re-performed.

Even after a large load is put into service, significant changes in its load profile (e.g., switching from traditional cloud services to large-language model training) could result in power quality violations that may not have been identified in earlier studies. It may then become necessary to specify and install additional equipment (e.g., harmonic filters or active power conditioning devices) to mitigate the violation, incurring additional costs and potentially altering the interconnection timeline.

TOs and DPs should have clear policies in place to handle such scenarios along with the appropriate measures that may be taken to ensure system reliability (e.g., operational restrictions or other mitigations). Additionally, based on the severity of the violation, timelines for remediation could be determined without immediately impacting the operational status of the project (e.g., a minor violation may be permitted to continue without operational downtime for the project so long as it is resolved within a reasonable amount of time).

TOs and DPs should have policies for addressing unanticipated power quality impacts that are not covered by limits set forth in interconnection agreements. For example, it is possible that demand fluctuations at a large load may cause the lights of other nearby customers to flicker, even if the load owner is subjected to and compliant with relatively strict interharmonic limits. There is also the possibility of unforeseen interactions between equipment at multiple large load facilities or IBRs that are electrically close to one another. TOs and DPs should have policies in place that enable cooperation with load owners to resolve these issues.

Power Quality Monitoring and Analysis

TOs should install high-resolution data monitoring equipment at the point of interconnection substation to collect operational power quality measurements. This data can be used to validate the accuracy of expected power quality performance (e.g., load profile), compliance with power quality performance limits, and whether the large load is participating in system power quality issues. In the event of system-level power quality impacts, TPs and PCs should use the validated as-left load models to perform power quality studies to mitigate any identified deficiencies and propose solutions.

[46] Here, 10% is provided as an example criteria, and entities may choose to implement a different value for their criteria.

Chapter 7: Physical and Cyber Security

This chapter provides recommendations for NERC registered entities and large load entities to systematically integrate physical and cyber security considerations into the planning, design, and integration processes for new or existing large industrial loads. The objective is to ensure that the integration of such large load facilities maintains or enhances the reliability, resilience, and security of the electric grid, consistent with NERC Reliability Standards and good utility practice. This chapter is informed by the initial work of the NERC LLWG as documented in its white papers, *Characteristics and Risks of Emerging Large Loads* and *Assessment of Gaps in Existing Practices, Requirements and Reliability Standards for Emerging Large Loads*. It emphasizes proactive risk mitigation for both physical and cyber threats, recognizing the potential impact of large load facilities on regional and interconnected system stability.

Holistic Risk Assessment

NERC registered entities and large load entities should conduct comprehensive, forward-looking risk assessments that integrate physical and cyber threat vectors impacting both the large load facility itself and its point of interconnection with the BPS. This assessment should consider the potential for cascading impacts on the wider grid. The assessment should also account for the unique operational characteristics and potential vulnerabilities of diverse large loads, including data centers and industrial facilities with BTM power generation and storage resources, as well as demand-side management capabilities. The results of this assessment should be used to inform potential mitigating actions needed.

Security-by-Design

NERC registered entities and large load entities should advocate for and require the incorporation of physical and cyber security controls as foundational elements during the design phase of new large load interconnections rather than as retrofitted additions. This approach should address new cyber attack vectors introduced by the growing adoption of internet-connected process control networks (PCN), operations management networks (OMN), and industrial control systems (ICS) and the potential for these loads to participate in energy markets as aggregated distributed energy resources.

Operational Interdependency Recognition

NERC registered entities and large load asset owners should acknowledge and plan for the operational interdependencies between the large load's internal systems (e.g., industrial control systems, microgrid controls) and the utility's BES control systems, ensuring secure and reliable data exchange and control capabilities.

Collaboration and Information Sharing

NERC registered entities and large load asset owners should foster effective communication and collaboration from the earliest stages of a project. This collaboration is crucial for identifying, assessing, and effectively mitigating evolving security challenges and may necessitate updates to existing NERC Reliability Standards and the development of new best practices. The interconnection agreement and applicable tariffs serve as the primary legal and contractual mechanisms to formally define the terms of this collaboration and information sharing.

Physical Security Considerations for Large Load Interconnection

Site Selection and Layout Review (CIP-014 Alignment)

- **Purpose:** To identify and mitigate physical security risks associated with the location and configuration of large load facilities and their immediate interconnection infrastructure.

- **Guideline:** NERC registered entities and large load asset owners should perform an initial assessment of the potential criticality of the proposed interconnection substation and associated transmission elements if subjected to physical attack (aligned with CIP-014 principles). The physical environment, accessibility, and visibility of the proposed site should be analyzed, and design features that inherently enhance physical security should be recommended. This includes advising on robust perimeter security for critical components. Entities may also consider incorporating geospatial risk analysis, considering proximity to urban areas, transportation hubs, or known threat sources.

Equipment Protection and Resilience

- **Purpose:** To ensure that critical equipment supporting the large load interconnection is adequately protected against physical threats and can withstand or recover from attacks.
- **Guideline:** Recommend hardening measures for critical control houses, communication infrastructure, and vulnerable equipment for large load assets. This includes physical security for control cabinets or converter stations for devices like STATCOM/FACTS/BESS/HVdc converters as well as adequate physical hardening of substations where these devices are installed. Opportunities for redundant physical pathways or diverse equipment routing should be explored to minimize single points of failure. Both NERC registered entities and large load asset owners should also coordinate on strategies for rapid replacement of critical long lead-time equipment.

Detection, Surveillance, and Response Integration

- **Purpose:** To ensure that physical security measures at the large load's interconnection point are integrated into broader utility security operations.
- **Guideline:** NERC registered entities and large load asset owners should implement and integrate surveillance (like closed-circuit television), intrusion detection systems, and access control systems. This should address the lack of physical security measures for critical OT components like remote terminal unit, PMUs, static VAR compensator control houses, BESS containers, HVdc converter stations, and communication nodes. Joint discussions and planning between the large load entity, the interconnecting utility, and local law enforcement/first responders should be facilitated for unified response to physical security incidents. Surveillance systems should feed into the utility's security operations center for real-time monitoring and response coordination.

Cyber Security Considerations for Large Load Interconnections

Secure Network Design and Architecture (CIP-005, CIP-007 Alignment)

- **Purpose:** To ensure that the network architecture supporting the large load interconnection is designed to prevent, detect, and respond to cyber incidents.
- **Guideline:** NERC registered entities and large load asset owners should mandate robust network segmentation between the large load's operational technology and IT networks. They should require the use of encrypted and authenticated communication protocols for all data exchange. They should also establish strict controls and secure methods for any remote access to critical systems at the large load facility that could impact the BPS.

Supply Chain Risk Management (CIP-013 Alignment)

- **Purpose:** To mitigate cyber security risks introduced through the supply chain of equipment and software utilized in the large load interconnection.

- **Guideline:** Large load asset owners should conduct cyber security due diligence on vendors providing control systems, network devices, and critical software for their interconnection.

Vulnerability Management and Patching (CIP-007 Alignment)

- **Purpose:** To ensure ongoing management of vulnerabilities in systems related to the large load interconnection.
- **Guideline:** Large load asset owners should perform regular vulnerability assessments and penetration testing for critical systems within the large load's operational environment that interface with the BPS. They should also establish protocols for coordinating patching and security updates.

Incident Response and Recovery Planning (CIP-008 Alignment)

- **Purpose:** To ensure the capability to detect, respond to, and recover from cyber security incidents impacting the large load interconnection.
- **Guideline:** NERC registered entities and large load asset owners should facilitate the development of joint cyber security incident response plans. They should also emphasize robust data backup and system restoration capabilities for critical systems at the large load facility that impact BES reliability. The interconnection agreement should include a jointly developed and tested incident response plan with clear communication protocols, roles, and responsibilities. Large load asset owners could encourage staff participation in E-ISAC GridEx exercises.[47]

Documentation, Review, and Continuous Improvement

Documentation Requirements: All analyses, recommendations, and agreements stemming from the physical and cyber security assessments should be thoroughly documented.

Review and Update Cycle: This guideline and its application should be reviewed periodically to ensure continued relevance and effectiveness. Any updates to the security posture should be formally amended into the interconnection agreement. Large load entities should conduct annual security posture reviews, aligning with NERC audit cycles, and amend agreements as needed.

Training and Awareness: Large load entities should regularly train their personnel on the importance of physical and cyber security. This should address the critical gap regarding personnel security and training for large loads.

[47] E-ISAC's GridEx exercises are comprehensive, large-scale, biennial events that simulate coordinated cyber and physical attacks on North America's electric grid to test and improve crisis response and resilience.

Chapter 8: Resilience, System Restoration, and Load Shedding

In a 2018 report, NERC's Reliability Issues Steering Committee created a resilience framework that focuses on four outcome-based abilities of resilience: robustness, resourcefulness, rapid recovery, and adaptability.[48] Resilience is similarly defined by the NATF and EPRI as "the ability of the system and its components (both equipment and human) to 1) prepare for, 2) anticipate, 3) absorb, 4) adapt to, and 5) recover from non-routine disruptions, including high impact-low frequency (HILF) events, in a reasonable amount of time…".[49] Typical Bulk Electric System (BES) resilience infrastructure facilities include manual load shedding, automatic load shedding, and system restoration.

Large loads, with their high power ratings and dynamic characteristics, can introduce challenges to BES resilience. This chapter analyzes reliability risks posed by large loads, identifies key gaps, and proposes mitigation measures to enhance BES resilience.

Load Shedding

Manual Load Shedding

NERC EOP-011 requires BAs and TOPs to have the capability and provisions to implement manual load shedding (MLS) to mitigate emergencies. Additionally, it mandates provisions to minimize the overlap among circuits designated for MLS, UVLS, and UFLS. In areas with a high penetration of large loads, avoiding overlap among these programs may be difficult if large loads are excluded from participation. Therefore, TOs should consult with BAs and TOPs to determine whether including large loads in MLS plans is appropriate. Additionally, BAs and TOPs, in coordination with TOs, should consider whether it is appropriate to implement dynamic MLS using real-time SCADA to adjust shed amounts based on current load profiles.

Given that the load profile of large loads may be conforming or non-conforming to the aggregate system load profile, shedding them based on the UFLS prediction could result in failing to meet the load-shedding obligation or shedding too much load, leading to overfrequency and/or overvoltage situations.

The following recommendations aim to address these issues:

- **Monitor Actual Load Consumption:** Real-time monitoring, such as SCADA or telemetry, is critical for TOPs to accurately control the amount of load shed. Large loads participating in MLS should be equipped with such monitoring systems.
- **Partial Load Shedding:** Segmenting a large load into controllable blocks allows for more precise load shedding while maintaining service to other parts. TOPs and RCs should develop guidelines and standards for partial load shedding of large loads in coordination with large load entities.
- **Consider co-located and BTM configurations:** TOPs and RCs should consider the effect of any co-located or BTM generation when designing and executing load shed plans.
- **Incorporate Data Center Flexibility:** Some data centers have flexibility to rapidly change their demand by rescheduling or shifting machine learning workloads and non-urgent compute tasks to

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[48] NERC, *Reliability Issues Steering Committee - Report on Resilience,* November 2018. https://www.nerc.com/globalassets/who-we-are/standing-committees/risc/risc-resilience-report_approved_risc_committee_november_8_2018_board_accepted.pdf

[49] NATF and EPRI, *Understanding the Definition of Resilience (Companion Document),* November 2025. https://www.natf.net/docs/natfnetlibraries/documents/resources/resiliency/understanding-the-definition-of-resilience-(companion-document).pdf

support the grid.[50] Agreements and protocols can be set up between TOPs and large load entities on integrating these flexibilities to support the grid when necessary.

- **Coordination with Load Owners:** TOs/TOPs and large load entities should establish communication pathways to coordinate expected load shedding needs.
- **Regular Obligation Review:** RCs and TOs should increase the frequency of reviewing load shedding obligations to keep pace with large load growth.

Automatic Load Shedding

NERC PRC-006 defines design and documentation requirements for automatic UFLS programs. The aim of these programs is to balance system load with available generation sources in the event of a system-wide incident that causes a shortage of available generation to meet the connected load. Due to the size of large loads ranging from tens to thousands of megawatts, as well as the high penetration of multiple large loads in a given PC area, it may be necessary to include large loads as part of UFLS schemes to satisfy the PRC-006 performance criteria. Large loads may cause significant load growth in some areas, which causes the relative percentage of UFLS load to be reduced to below 25%. Therefore, TOs should coordinate with PCs and use studies to determine if it is appropriate to include the large loads in their UFLS programs (e.g., TOs and PCs may require large loads to design and operate facilities to have the capability to participate in automatic UFLS or in distribution management system (DMS) control, in accordance with relevant standards like PRC-006). Large load entities should provide, and TOs should collect, all necessary information about facility protections and transfer schemes that may impact UFLS, UVLS, or MLS programs. Finally, responsibilities should be clearly defined for design, control, and operation of necessary equipment for UFLS, UVLS, and MLS and coordinated between the large load entity, TO, TOP, and other relevant parties.

PRC-006 requires the frequency of each identified island to remain within the defined range for underfrequency conditions resulting from an imbalance of up to 25%. The departure of actual UFLS stage percentages from obligation percentages at any time could result in insufficient or excessive UFLS capability available from PRC-006 design basis of 25%.[51] For a UFLS program originally established to include at least 25% of the total load, when one or more non-UFLS participating large load(s) are added to the total load, the original stationary UFLS percentage may not sustain and may need to change depending on if the large load is on-line or off-line and if the other loads are at peak or minimum demand. Keeping the original static UFLS percentage could cause insufficient or excessive UFLS and may result in the frequency excursion.

The recommendations include the following:

- **Improved Observability:** TO, TOP, DP and other UFLS entities should monitor real-time changes in UFLS load percentage.
- **Set Load Variability Bounds:** PCs should define acceptable load variability ranges.
- **Coordinate Across Areas:** BAs should coordinate to synchronize UFLS staging between exporting and importing areas, which can reduce transmission stress.
- **Coordinate with Large Load Protection and Control Settings:** Large loads are sensitive to system frequency/voltage changes and can automatically switch to internal backup generation (equivalent to large load shedding for the grid) when large frequency/voltage deviations are observed at their

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[50] Google, *How we're making data centers more flexible to benefit power grids*, August 2025. https://blog.google/inside-google/infrastructure/how-were-making-data-centers-more-flexible-to-benefit-power-grids/

[51] R. O'Keefe*, Proposed PRC-006 SAR for UFLS Variability Monitoring and Stage Percent Bounds*, presented at the Large Loads Task Force Meeting, June 2025. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_june_workshop_presentations.pdf

terminals. Thus, TOs and BAs should consider such behaviors in their UFLS settings and program design.

- **Partial Load Shedding:** Segmenting a large load into controllable blocks allows for more precise load shedding while maintaining service to other parts. TOPs and BAs should consider partial load shedding of large loads in coordination with large load entities where feasible.

Similarly, NERC PRC-010 establishes an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS programs. In some cases, large loads may be of significant size or clustered in an area where inclusion of large loads as part of UVLS schemes is needed to satisfy the PRC-010 performance criteria. Therefore, TOs should coordinate with PCs to determine if it is appropriate to include the large loads in their UVLS programs.

Both PRC-006 and PRC-010 require each PC or TP to evaluate the effectiveness of each UFLS and UVLS program at least every five years. Given that large loads can be constructed in as quickly as 12 –18 months and due to rapid large load deployments, an assessment every five years may not be sufficient. PCs and TPs should dynamically adjust the UFLS and UVLS assessment frequency based on the load growth rate of their system or define a system load deployment threshold that triggers new UFLS or UVLS assessments if the threshold is passed. This will ensure UFLS and UVLS reliability in areas with fast load growth. If new assessments are not performed, then the BPS may collapse if UFLS or UVLS schemes are triggered but prove inadequate due to load growth.

If a TO determines that a large load is part of its MLS, UVLS, or UFLS schemes,[52] the TO should require the large load to coordinate with the testing, maintenance, and design scheme (e.g., feeder breaker tripping) to support implementation.

Additionally, due to the voltage sensitivity of some types of large loads and the potential for simultaneous disconnection during a single fault or disturbance due to collective ride-through behavior, TP and PCs should also assess frequency stability, including overfrequency performance, the need for overfrequency protection schemes, and the MSSC on the demand side. TPs should require large load entities to submit the ride-through capability data of the load and the test report including the as-built ride-through characteristics, which should be modeled and considered in the planning and operational analyses.

Dynamic Load Shed Monitoring and Allocation

If large loads are included in load shed plans such as MLS, UVLS, or UFLS, then TOs and DPs should coordinate on a real-time basis if dynamic computation of load shed allocation is implemented. TOs and DPs should develop communication protocols to automatically communicate load shed percentages in real time to protection systems in the field. TOs should assess the need for a wide-area measurement system (WAMS) and a wide-area protection scheme that dynamically sets and adjusts load shed allocations for both manual load shed and automatic load shed functions.

[52] There is a DP-UFLS registered entity according to NERC ROP Appendix 5B: A Distribution Provider entity shall be an Underfrequency Load Shedding (UFLS)-Only Distribution Provider if it is the responsible entity that owns, controls or operates UFLS Protection System(s) needed to implement a required UFLS program designed for the protection of the BES, but does not meet any of the other registration criteria for a Distribution Provider. A DP designated as 'DP – UFLS Only' will only be accountable for a sub-set of the NERC Reliability Standards as described in Section III.b.2 of NERC ROP Appendix 5B, Statement of Compliance Registry Criteria.

System Restoration

System operators maintain blackstart procedures to restore the grid following widespread outages. The integration of large loads challenges traditional assumptions due to their scale and flexibility and the fact that load operators may not have previously interacted with system operators. These procedures should be updated accordingly to ensure that TOPs can reliably blackstart the grid with large loads.

Load Coordination

While load restoration is a crucial element of blackstart, large loads specifically are unlikely to be restored in early stages of blackstart unless they play a critical role in BPS reliability (e.g., gas compressor stations). During system restoration, TOPs, BAs, and RCs must match load pickup with generation availability and keep load constant and controlled. Uncontrolled load pickup creates large voltage and frequency swings that can negatively impact the stability of blackstart islands and potentially collapse the island. In the past, the TOP would work with the DP to operate distribution equipment (e.g., breakers and switches) to energize load and the load behavior could primarily be safely assumed. With large loads, a single load may be selected for priority restoration and may energize in stages in coordination with the load operator. To accomplish this, the TOP and large load entity should establish communication paths to coordinate during system restoration. Without a communication path, the load cannot be adequately managed for reliable use in blackstart procedures.

While TOPs and RCs have traditionally considered the impact of cold load pickup, large loads may exhibit new variations. If large loads are restored early on, they pose a risk to the blackstart island stability as the stability of the island is sensitive to changes in frequency and voltage. To mitigate this, the TOP, BA, and RC should establish limits for load variability and blackstart island load ramping in the islands and along the cranking paths and review the priority of large loads in their restoration plans.

Modeling and Simulation for Restoration Studies

To perform accurate studies for selecting blackstart units and cranking paths, it is important for the system operator to obtain information about the load it intends to pick up early in the system restoration process. The TOs, BAs, and RCs should gather the data mentioned in **Chapter 1** and reflect them in the model used for system restoration analysis.

Without this information to build the precise model, the system operator is limited in its ability to perform accurate blackstart analyses or create reliable restoration plans.

Given the growing dynamics and uncertainties with these large load behaviors, TOPs should perform detailed restoration studies using transient stability and/or electromagnetic transient simulation tools with appropriate or best-known load models to verify the effectiveness of the restoration plans regularly and adjust their plans to mitigate potential issues.

Chapter 9: Conclusion

In summary, large loads are being integrated faster than ever and at a scale never before seen. New processes will be needed, and existing processes should be updated to mitigate risks to the BPS from large loads. Although the RSTC Charter requires a review for continued applicability at least every three years for reliability guidelines, with recent large load growth, this reliability guideline may require more frequent reviews as needed (particularly as NERC is working with stakeholders on updates to registry criteria and Reliability Standards to account for large load integration).

Data collection and sharing are foundational to ensuring that accurate assessments can be performed by NERC registered entities. Similar to recent strides in model quality for IBRs, large loads require comprehensive model verification and model validation processes to ensure accurate modeling and reliable operations. This will require strong, ongoing coordination between OEMs, large load entities, and existing NERC registered entities. This also requires dynamic modeling to be accounted for in the earliest stages of design, as opposed to an afterthought once the facility design is complete.

DPs and TOs, in coordination with TPs and PCs, are responsible for creating and enforcing interconnection requirements that account for local and system-wide reliability-enhancing processes, including modeling, coordination, analysis, performance, and real-time monitoring. Additionally, new risks and failure modes require TPs and PCs to update their interconnection and planning study processes to ensure that key risks are analyzed and mitigated.

New challenges are being introduced to grid operators, and increased coordination along with new operational requirements can mitigate those challenges. Grid operators will need new data to inform processes that ensure reliable operations, like receiving real-time telemetry and near-term forecasts from large load entities. Additionally, BAs and RCs will need to plan for increased non-conforming variable loads in real-time operations.

Stability risks are clearly demonstrated in prior incident reviews and other analyses. Some of the stability risks mentioned in **Chapter 5** can lead to instability, cascading, and uncontrolled separation before operators even have a chance to intervene. Improved data collection, post-event analysis, and dynamic planning studies will be required to prevent critical risks in the stability domain.

Power quality, while currently deemed a lower-likelihood risk, should be accounted for, monitored, and analyzed.

Physical and cyber security, similar to dynamic modeling, should be integrated into facility design at an early stage and coordinated with relevant NERC registered entities.

Finally, load shedding and system restoration risks require consideration at early stages of large load facility design. These risks also require new analysis and coordination from existing NERC registered entities.

Appendix A: High-Level Recommendations

Category	Recommendation	LLE	DP	TO	TP	PC	TOP	BA	RC
Data Collection and Modeling	Provide steady-state, dynamic, and other data	P	L	L	SR	SR			
	Install high-speed FR, DDR, and SER	L	C	C					
	Provide high-speed recording data for post-event analysis	P	C	C	C	C	SR	SR	SR
	Provide updates to modeling data (as-built)	P	L	L	SR	SR			
	Provide real-time electrical measurements	P		P			SR	SR	SR
	Provide near-term demand forecasts	P		C				SR	SR
	Perform model quality assessment, model verification, model validation	L			SR	SR			
Interconnection	Collect data and share with relevant entities	C	L	L	SR	SR	SR	SR	SR
	Study reliability impacts of new large load	C	C	C	L	L	M	M	M
	Periodic near-term studies for collective impact of new large loads	C	C	C	L	L	M	M	M
	Comprehensive commissioning process for large loads	C	C	C	C	C	SR	SR	SR
	Develop EMT screening criteria where needed	M	C	C	SR	SR			M
Long-Term Planning	Study reliability impacts of new large load	C	C	C	L	L	M	M	M
	Resource adequacy analysis considering unique risks of large loads	C	C	C					
Operations and Balancing	Verify communications (phone communications, telemetry, etc.)	C					SR	SR	SR
	Integrate into operational systems (forecasting, outages, day-ahead studies)	C					SR	SR	SR
	Conduct commissioning tests of the large load	C		C			SR	SR	SR
	Post-commissioning testing and verification	C					SR	SR	SR
	Provide real-time electrical measurements	P		P			SR	SR	SR
	Provide near-term demand forecasts	P		C				SR	SR
	Specify data requirements for large loads real-time analysis and monitoring	C					SR	SR	SR
	Prepare for largest expected load contingency (CILR, ramping, or other)	C			C	C		SR	SR
	Minimize variability via large load facility software mitigations	L						SR	SR
	Respond to operating instructions	L					SR	SR	SR
	Event analysis	C			L	L	L	L	L
Stability	Define disturbance performance criteria based on studies	C	C	C	C	SR	C	C	SR
	Study and mitigate risks from CILR events	C	C	C	L	L	M	L	L
	Design and operate facilities to follow disturbance performance criteria	L	C	C	SR	SR	C	C	SR
	Study, mitigate, and monitor oscillations from large loads	C	M	L	L	L	C	M	SR
Power Quality	Study, mitigate, and monitor power quality risks from large loads	C	M	L	L	C	C		C
Physical and Cyber Security	Holistic risk assessment	L							
	Implement security-by-design practices	L							
	Study and plan for operational interdependency between utility and large loads	C	C	C	C	C	C	C	L
	Implement physical security considerations	L							
	Implement cyber security considerations	L							
Resillience	Monitor any large loads involved in manual load shed, UFLS, and UVLS	C	C	C			L	L	
	Consider integration of large loads into UFLS and UVLS schemes	C	L	L			L	L	

C = Coordinate   L = Lead   M = Monitor   P = Provide   SR = Specify Requirements

Appendix B: Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline.

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Appendix C: Guideline Information and Revision History

Guideline Information	
Category/Topic: [NERC use only]	Reliability Guideline/Security Guideline/Hybrid: Reliability Guideline
Identification Number: [NERC use only]	**Subgroup:** Large Loads Working Group

Revision History		
Version	**Comments**	**Approval Date**
1.0		April 30, 2026

Appendix D: Metrics

Pursuant to the Commission's Order on January 19, 2021, North American Electric Reliability Corporation, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- [Insert metrics specific to the content of this reliability guideline here]

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- Industry survey on effectiveness of Reliability Guidelines;
- Triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

Guideline Effectiveness Survey