Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

MOD-032-2 is posted for a 34-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025

Anticipated Actions	Date
34-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Distributed Energy Resource (DER): A generators or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**
2. **Number:** **MOD-032-~~1~~2**
3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.
4. **Applicability:**

   ~~1.1.~~4.1. **Functional Entities:**

   ~~1.1.1~~4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   ~~1.1.2~~4.1.3 Generator Owner

   ~~1.1.3 Load Serving Entity~~

   ~~1.1.4~~4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   ~~1.1.5~~4.1.5 Resource Planner

   ~~1.1.6~~4.1.6 Transmission Owner

   ~~1.1.7~~4.1.7 Transmission Planner

   ~~1.1.8~~4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

   ~~MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is~~

~~approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**Background:**~~

~~MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.~~

~~The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).~~

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator’s planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation.

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each ~~registered~~functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~2.1.~~3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data~~;~~, that is responsive to the technical concern.

~~3.1.~~3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each ~~registered~~functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention: The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance ~~with~~ as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

2. Compliance Monitoring and ~~Assessment Processes~~ Enforcement Program:
Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for ~~a list of~~performing compliance monitoring and ~~assessment processes~~enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

~~**1.3. Additional Compliance Information**~~

~~None~~

3. Potential Noncompliance (PNC) Abeyance Period:
For a period of two years following the compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for

an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. “Good faith” in this context refers to a sincere intention to comply with Reliability Standard MOD-032-2 regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator’s planning area developed under Requirement R1, subject to the estimation requirements of Requirement R2 Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R2.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;

	the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures~~,~~ but did provide the data in less than or equal to 15 calendar days after the specified date.	greater than 25%~~,~~ but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures~~,~~ but did provide the data in greater than 15~~,~~ but less than or equal to 30 calendar days after the specified date.	greater than 50%~~,~~ but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures~~,~~ but did provide the data in greater than 30~~,~~ but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its

				Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

- ~~None.~~Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List
- MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO).

MOD-032-2 – ATTACHMENT 1~~:~~

Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in ~~*the*~~ Interconnection-wide cases. ~~*A*~~The joint Planning Coordinator ~~*may*~~/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify ~~*additional information that includes specific information required for each item in the table below. Each*~~entity responsibility and data flow processes. The typical functional *entity*~~[1]~~[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be ~~*as*~~ identified by the bus number, name, and/or identifier that is assigned in conjunction with the ~~*PC, TO*~~Planning Coordinator, Transmission Owner, or ~~*TP.*~~ Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
1. Each bus [TO] a. ~~n~~Nominal voltage b. ~~a~~Area, zone and owner 2. Aggregate Demand[3]~~[2]~~ [~~LSE~~DP] a. ~~r~~Real and reactive power* b. ~~i~~In-service status*	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System ~~S~~stabilizer [GO, RP(for future planned resources only)]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO]

~~[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).~~

~~[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
3. Generating and storage Units[4]~~[3]~~ [GO, TO[5], RP (for future planned resources only)] a. ~~r~~Real power capabilities - gross maximum and minimum values b. ~~r~~Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. ~~s~~Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. ~~r~~Regulated bus* and voltage set point* (as typically provided by the TOP) e. ~~m~~Machine MVA base f. ~~g~~Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. ~~g~~Generator type (hydro, wind, fossil, solar, nuclear, etc) h. ~~i~~In-service status* 4. AC Transmission Line or Circuit [TO] a. ~~i~~Impedance parameters (positive sequence) b. ~~s~~Susceptance (line charging) c. ~~r~~Ratings (normal and emergency)* d. ~~i~~In-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. ~~n~~Nominal voltages of windings	5. Aggregated Demand[3] [~~LSE~~DP] 6. Wind ~~T~~turbine ~~Data~~model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]]~~Photovoltaic systems [GO]~~ ~~7.~~a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control. 8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC ~~s~~System models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

~~[3] Including synchronous condensers and pumped storage.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
b. ~~i~~Impedance(s) c. ~~t~~Tap ratios (voltage or phase angle)* d. ~~m~~Minimum and maximum tap position limits e. ~~n~~Number of tap positions (for both the ULTC and NLTC) f. ~~r~~Regulated bus (for voltage regulating transformers)* g. ~~r~~Ratings (normal and emergency)* h. ~~i~~In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. ~~a~~Admittances (MVars) of each capacitor and reactor b. ~~r~~Regulated voltage band limits* (if mode of operation not fixed) c. ~~m~~Mode of operation (fixed, discrete, continuous, etc.) d. ~~r~~Regulated bus* (if mode of operation not fixed) e. ~~i~~In-service status* 8. Static Var Systems [TO] a. ~~r~~Reactive limits b. ~~v~~Voltage set point* c. ~~f~~Fixed/switched shunt, if applicable d. ~~i~~In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.)		

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

~~Guidelines and Technical Basis~~

~~For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.~~

~~The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.~~

~~An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.~~

~~The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and~~

~~to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).~~

~~The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for R1:~~

~~This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.~~

~~In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.~~

~~This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.~~

~~This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:~~

~~Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:~~

1) ~~reduce the quantity of MOD standards;~~
2) ~~add short circuit data as a requirement to the MOD standards; and~~
3) ~~supply data and models:~~
    a. ~~add requirement identifying who provides and who receives data;~~
    b. ~~identify acceptability;~~
    c. ~~standard format;~~
    d. ~~how to deal with new technologies (user written models if no standard model exists); and~~
    e. ~~shareability.~~
4) ~~These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.~~
5) ~~The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.~~
6) ~~Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.~~

~~Rationale for R2:~~

~~This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."~~

~~Rationale for R3:~~

~~In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.~~

~~This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.~~

~~Rationale for R4:~~

~~This requirement will replace MOD-014 and MOD-015.~~

~~This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.~~

~~The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).~~

~~This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).~~

~~For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.~~

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs, and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider’s system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner’s system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This attachment describes the process by which changes may be made to the Unacceptable Models List.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
   a. The model name;
   b. Alternative model name(s), if any;
   c. Organization(s) the submitting entity represents;
   d. Description of the model's stated intent;
   e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
   f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
   g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
   h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.

5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.
6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.