Technical Rationale

Project 2021-01 System Model Validation with IBRs
Reliability Standard MOD-033-3 | August 2025

MOD-033-3 – Steady-State and Dynamic System Model Validation

Rationale for Requirement R1

In FERC Order No. 693, the Commission directed inclusion of "a requirement that the models be validated against actual system responses."[1]The Commission further directed "that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy."[2] Similarly, the Commission directed validation against actual system responses relative to dynamics system models.[3] In FERC Order No. 890, the Commission stated that "the models should be updated and benchmarked to actual events."[4]

In FERC Order No. 901, a wide spectrum of directives was issued to address reliability risks to the grid from the application of Inverter Based Resources (IBRs), including directives related to system model validation. The Commission directed NERC to "submit new or modified Reliability Standards that require Bulk-Power System planners and operators to validate…system models against actual system operational behavior."[5] The Commission further directed development of "new or modified Reliability Standards that require…the validation of each respective system model" and mandates a process to "validate, and keep up to date the transmission planning, operations, and interconnection-wide models."[6]

Consistent with the Commission directives, Requirement R1 requires the Planning Coordinator (PC) to implement a documented system model validation process for the PC's portion of the existing system by comparing performance of the steady-state and dynamic models of the existing system against actual system behavior. Revisions made to Requirement R1 in MOD-033-3 are to improve clarity of the requirement, including clarifying that planning System models will include registered IBRs, unregistered IBRs, or aggregated DERs present in the existing System consistent with Reliability Standard MOD-032, and are not substantive in nature. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees and is not addressed by this standard.

Implementation of these validation requirements will result in more accurate power flow and dynamic system models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values occurring in system operations. Similar improvements should

[1] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, at P 1210, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[2] Order No. 693 at P 1211.
[3] Order No. 693 at P 1220.
[4] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 181 FERC ¶ 61,119, at P 290 (2007).
[5] *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, at P 156 (2023).
[6] Order No. 901 at P 161.

be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Requirement R1 focuses on the results-based outcome of the Planning Coordinator developing a process for, and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement (parts 1.1 through 1.4). The specifics of the validation process are left to the judgment of the PC, but the PC is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior and expected system performance for determining whether the discrepancies are unacceptable.

For information on recommended methods and procedures for system model validation, including suggested criteria (i.e. mismatch thresholds) to evaluate unacceptable discrepancies in the steady-state and dynamic model performance, the Planning Coordinator may refer to:

1. MOD-033-1 Methodology Reference Document (NATF) – an ERO Endorsed Implementation Guidance[7]
2. Procedures for Validation of Powerflow and Dynamics Cases (NERC), 2013 – developed by the NERC Model Validation Working Group (MVWG)[8]
3. System-Wide Model Validation (EPRI)[9]

Much of the technical guidance in the following sections, including Table 1, is from the MOD-033-1 Methodology Reference Document (NATF) listed above.

Rationale for Requirement R1, Part 1.1

Requirement R1 Part 1.1 addresses validation of steady-state data. Revisions made to Requirement 1, Part 1.1 in MOD-033-3 are to improve clarity of the requirement and are not substantive in nature.
This section outlines the key components of the data validation and case setup process for PCs to meet Requirement R1, Part 1.1. As part of this process, an existing planning power flow model is adjusted to align with the conditions represented in an Energy Management System (EMS) case. The key steps are as follows:

The Reliability Coordinator (RC) and Transmission Operator (TOP) must provide actual system behavior data (or a written response that it does not have the requested data) such as, but not limited to, the state estimator case or other real-time data (including Supervisory Control and Data Acquisition (SCADA) or Phasor Measurement Unit (PMU) data or disturbance data recordings) to Planning Coordinators performing validation.

The Drafting Team's intention and interpretation is that development and implementation of a process to produce planning steady-state System models from the same data source as state estimator cases or

---

[7] MOD-033-1 Methodology Reference Document.pdf
[8] NERC_Model_Validation_Procedures_v3.pdf
[9] System-Wide Model Validation

other Real-time model cases is a valid alternative to performing an explicit steady-state model comparison.

For example, if an entity has:

- implemented a single modeling repository for both operations and planning cases;
- implemented a process to compare state-estimated solution values to telemetry, identifying potential mismatches between the model and the real-world transmission system; and
- demonstrated that mismatches are investigated and resolved via model updates within the model repository,

This process would be acceptable without needing a separate and explicit comparison between planning steady-state System models and the state estimator cases or other Real-time models.
To enable a more effective comparison, the planning model should be adjusted to align with the system conditions in the EMS case. In adjusting the planning model, the PC should consider items such as, but not limited to, the following:

- Transmission/generation outages
- Transmission topology changes
- Area interchange
- Generation dispatch
- Generator scheduled voltage
- Loads
- Switched shunts status/position
- Transformer tap positions (fixed and adjustable)
- Power Electronic and Flexible AC Transmission System (FACTS) devices

The PC may choose to compare power flows at every location in the system or focus on key parts of its system such as certain voltage levels, critical interfaces, or tie lines. Real and reactive power flows, as well as voltages, should be compared. Further validation checks can be performed including validating generator capability values (Pmax, Pmin, Qmax, and Qmin), voltage schedules, and ensuring DERs are modeled appropriately.

Rationale for Requirement R1, Part 1.2
Requirement R1 Part 1.2 addresses validation of dynamic data. All revisions made to Requirement R1, Part 1.2 in MOD-033-3 are to improve clarity of the requirement and are not substantive in nature. The phrase “actual system response” was replaced with “actual system behavior” to align with the proposed NERC Glossary definition for Model Validation.

The scope of dynamic model validation in Requirement 1, Part 1.2 is intended to be limited to the PC’s portion of the system, and on dynamic local events.

A dynamic local event is a disturbance that results in a measurable transient response (such as oscillations, voltage fluctuations, or frequency deviations) within the PC's area. The event may occur locally or be part of a larger disturbance affecting multiple areas of the grid, originating either inside or outside the PC's area. If the event originated outside the PC's area it will be necessary to utilize a wide area system model and coordinate with other PCs to replicate the event.

Event selection for system model validation is best left to the judgment of the Planning Coordinator based on the available disturbance data recordings. When PCs have the ability to choose from multiple dynamic local events, the following considerations should guide their selection to achieve comprehensive system model validation:

- Events that capture variations in system conditions, including low and high penetration of inverter-based resources (IBRs) and load conditions that differ from past event analyses.
- Events that have dynamic impacts in a broad area of the PC's system such as balanced and/or unbalanced faults, generation loss, etc.

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in Requirement R1, Part 1.2 specify that the comparison period of "at least once every 24 calendar months" is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30-day time frame in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary, in the comparison), it would potentially be impossible to complete the comparison within the 24-month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of Requirement R1, Part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a "month 23" dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day one of month one, the PC has 24 calendar months from that dynamic local event's occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event's occurrence to complete the comparison.

This section provides guidance for the dynamic model validation process, focusing on comparing the actual system dynamic behavior to the selected dynamic local event.

Dynamic model validation will require adjustments to the planning power flow base case to pre-contingency event conditions. While the steady-state and dynamic system models can be validated separately, it may be more efficient to use the same event and power flow model for validation of both Requirement R1, Parts 1.1 and 1.2. The key aspects of dynamic model validation are outlined below.

After selecting a dynamic local event, the relevant data should be gathered from sources such as Dynamic Disturbance Recorders (DDRs), Phasor Measurement Units (PMUs), fault recorders (FRs), and sequence of event recorders (SERs) for the system and the time duration being simulated. The data should be obtained from the RC and/or TOPs in accordance with Requirement R2.

The power flow case set up process for dynamic model validation should follow the same approach outlined in Requirement R1, Part 1.1. The power flow case to be used for dynamic model validation should reflect pre-contingency operating conditions that align with the actual system conditions prior to event occurred.

Once the power flow model and dynamic data are prepared, initial transient simulation should be performed using the updated dynamic data. A no-disturbance simulation should result in a flat response with no oscillations. A disturbance simulation should show initial oscillations that dampen out acceptably over time.

The next step is to create an accurate sequence of events and switching file-based on data sources such as relay records, Sequence of Event records (SERs), SCADA, dispatcher logs, etc. To ensure proper validation the simulation should monitor key quantities such as system frequency, MW and Mvar out of generating units, Mvar output of a dynamic reactive/var device, MW and/or Mvar flows on transmission elements, voltage magnitudes at major buses, etc.

Rationale for Requirement R1, Part 1.3

Requirement R1, Part 1.3 establishes the PC as the responsible entity for determination of required accuracy when comparing simulation results against actual system behavior. Revisions made to Requirement 1, Part 1.3 in MOD-033-3 are to improve clarity of the requirement and are not substantive in nature.

Table 1 lists example guidelines for acceptable differences between the simulated and actual steady-state model validation (Requirement R1, Part 1.1). Values shown in Table 1 are illustrative. The guidelines the PC includes within its documented validation process should be appropriate for the PC's system. In performing the comparisons of flow, raw branch flow values could be used, or alternately the flow values can be normalized based on branch normal continuous rating (e.g. Rating A).

Table 1 – Example guidelines to identify acceptable differences between simulated and real-time data for steady-state validation	
Quantity	**Acceptable Differences**
Bus voltage magnitude	±2% (≥500 kV) ±3% (230≥kV≥345 kV) ±4% (100≥kV≥230 kV)
Generating Bus voltage magnitude	±2%
Real power flow	±10% or ±100 MW
Reactive power flow	±20% or ±200 Mvar
Difference in % normal loading	±10% based on branch normal continuous rating

Guidelines for the dynamic event comparison (Requirement R1, Part 1.2) may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results are consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not, using engineering judgment in making this decision. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. The dynamic comparison criteria should be appropriate for the Planning Coordinator's system.

Rationale for Requirement R1, Part 1.4

Requirement R1, Part 1.4 establishes the PC as the responsible entity for determination of a process to resolve unacceptable differences. No revisions were made to Requirement R1, Part 1.4 in MOD-033-3.

While this standard is focused on system model validation, the results may identify model data that needs to be corrected. If an unacceptable difference is identified, the guidelines the PC includes in its documented system model validation process to resolve differences in Requirement R1, Part 1.4 could include direct coordination with the model data owner, and, if necessary, utilize the triggers provided in NERC Reliability Standard MOD-032 for the PC to call for reviews of steady-state and dynamic data as listed in Attachment 1 of that standard. For data that is typically collected as part of MOD-032 but is governed by additional NERC standards, such as MOD-026, the PC should coordinate with the Generator Owner on an acceptable timeline for receiving the updated modeling data. In some cases, it might be better to use an "interim model" based on a model parameter update that can be determined from disturbance data until a final model is made available for use by the data provider.

Rationale for Requirement R2

Actual system behavior data is required to perform system model validation. Requirement R2 provides a mechanism for the PC to obtain this data. Revisions made to Requirement 2 in MOD-033-3 are to improve clarity of the requirement and are not substantive in nature. Existing Requirement R2 is sufficient for system model validation with IBRs.

For comparing the steady-state performance of the system (Requirement R1, Part 1.1), Real-time or state-estimator data is required. The RC and TOP have this data available. For comparing the dynamic performance of the system (Requirement R1, Part 1.2), Real-time data sources such as Disturbance data recording(s) are required. The RC and TOP could obtain this data via Reliability Standards PRC-002 and PRC-028 if they don't have this data readily available.

Real-time SCADA measurements can be used for model validation. Real-time data is generally sufficient, but state-estimator models may be of use when measurements are noisy or inaccurate due to meter quality or miscalibration. State-estimator results or cases improve the accuracy of SCADA measurements, but state-estimator models based on the system model being verified can make the system models appear to be better than they actually are. Care should be taken to verify that the state-estimator results are accurate and are not simply a solved case that used an incorrect system model.

This standard does not specify the locations or measurements necessary for validation of dynamic system models. The provided data should have a sampling rate sufficient to accurately capture the recorded event. The measurement quality stipulated in PRC-002 and PRC-028 is sufficient for dynamic system Model Validation. The output recording rate of 30 cycles per second of measured parameters specified in PRC-002 is sufficient for synchronous generators. The output recording rate of 60 cycles per second of measured parameters specified in PRC-028 is generally sufficient for buses with inverter-based resources, but higher sample rates can be desirable. PRC-002 and PRC-028 also provide guidance for the location of the measurement devices. Additional measurements, such as relay records or SCADA measurements near the local system event might also be necessary for performing dynamic system model validation for a specific local event and would be requested by the PC.